Sprague Resources LP
Form 10-Q
August 08, 2018
Table of Contents

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 June 30, 2018
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
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulations S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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

The registrant had 22,727,284 common units outstanding as of August 1, 2018.

Table of Contents

Table of Contents

Table of Contents

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

	June 30, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 8,607	$ 6,815
Accounts receivable, net	184,229	316,613
Inventories	179,350	335,859
Fair value of derivative assets	44,741	107,254
Other current assets	11,794	39,946
Total current assets	428,721	806,487
Fair value of derivative assets, long-term	15,612	7,493
Property, plant and equipment, net	350,303	350,059
Intangibles, net	65,747	71,891
Other assets, net	10,415	12,018
Goodwill	115,037	115,037
Total assets	$ 985,835	$ 1,362,985
Liabilities and unitholders' equity		
Current liabilities:		
Accounts payable	$ 69,493	$ 205,105
Accrued liabilities	55,108	49,038
Fair value of derivative liabilities	43,612	156,763
Due to General Partner	7,566	11,228
Current portion of working capital facilities	57,248	275,613
Current portion of other obligations	6,704	6,476
Total current liabilities	239,731	704,223
Commitments and contingencies		
Working capital facilities - less current portion	133,135	66,237
Acquisition facility	379,100	383,500
Fair value of derivative liabilities, long-term	5,047	8,265
Other obligations - less current portion	49,121	49,625
Due to General Partner	1,912	1,678
Deferred income taxes	18,352	17,623
Total liabilities	826,398	1,231,151
Unitholders' equity:		
Common unitholders - public (10,620,936 units and 10,446,539 units issued and outstanding as of June 30, 2018 and December 31, 2017, respectively)	204,859	193,977
Common unitholders - affiliated (12,106,348 units issued and outstanding)	(38,859)	(53,273)
Accumulated other comprehensive loss, net of tax	(6,563)	(8,870)
Total unitholders' equity	159,437	131,834
Total liabilities and unitholders' equity	$ 985,835	$ 1,362,985

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

1

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net sales	$741,656	$513,626	$2,072,804	$1,431,433
Cost of products sold (exclusive of depreciation and amortization)	696,673	469,058	1,880,655	1,264,204
Operating expenses	22,281	16,901	45,490	33,733
Selling, general and administrative	18,562	19,624	46,426	45,913
Depreciation and amortization	8,378	6,950	16,803	12,882
Total operating costs and expenses	745,894	512,533	1,989,374	1,356,732
Operating (loss) income	(4,238)	1,093	83,430	74,701
Other income	—	119	—	183
Interest income	169	88	281	172
Interest expense	(9,412)	(8,279)	(19,296)	(15,434)
(Loss) income before income taxes	(13,481)	(6,979)	64,415	59,622
Income tax benefit (provision)	286	(813)	(2,689)	(2,915)
Net (loss) income	(13,195)	(7,792)	61,726	56,707
Incentive distributions declared	(2,055)	(854)	(3,769)	(1,596)
Limited partners' interest in net (loss) income	$(15,250)	$(8,646)	$57,957	$55,111
Net (loss) income per limited partner unit:				
Common - basic	$(0.67)	$(0.39)	$2.55	$2.52
Common - diluted	$(0.67)	$(0.39)	$2.54	$2.48
Units used to compute net (loss) income per limited partner unit:				
Common - basic	22,727,284	22,319,704	22,726,320	21,864,875
Common - diluted	22,727,284	22,319,704	22,784,336	22,200,070
Distribution declared per unit	$0.6675	$0.6075	$1.3200	$1.2000

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

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net (loss) income	$(13,195)	$(7,792)	$61,726	$56,707
Other comprehensive income, net of tax:				
Unrealized gain on interest rate swaps				
Net gain (loss) arising in the period	1,290	(13)	3,231	289
Reclassification adjustment related to (gain) loss realized in income	(499)	(4)	(779)	116
Net change in unrealized gain (loss) on interest rate swaps	791	(17)	2,452	405
Tax effect	(5)	—	(18)	(7)
	786	(17)	2,434	398
Foreign currency translation adjustment	(58)	77	(127)	110
Other comprehensive income	728	60	2,307	508
Comprehensive (loss) income	$(12,467)	$(7,732)	$64,033	$57,215

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

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, 2016	$175,314	$(4,518)	$(34,576)	$ —	$(10,783)	$125,437
Conversion of subordinated units to common units	—	(40,393)	40,393	—	—	—
Net income	11,955	14,324	—	3,218	—	29,497
Other comprehensive income	—	—	—	—	1,913	1,913
Unit-based compensation	1,034	1,240	—	—	—	2,274
Distributions paid	(25,198)	(23,239)	(5,817)	(3,218)	—	(57,472)
Common units issued related to Carbo acquisition	31,401	—	—	—	—	31,401
Common units issued with annual bonus	161	210	—	—	—	371
Units withheld for employee tax obligations	(690)	(897)	—	—	—	(1,587)
Balance at December 31, 2017	$193,977	$(53,273)	$ —	$ —	$(8,870)	$131,834
Net income	27,402	31,237	—	3,087	—	61,726
Other comprehensive income	—	—	—	—	2,307	2,307
Unit-based compensation	114	130	—	—	—	244
Distributions paid	(15,462)	(15,617)	—	(3,087)	—	(34,166)
Units withheld for employee tax obligations	(1,172)	(1,336)	—	—	—	(2,508)
Balance at June 30, 2018	$204,859	$(38,859)	$ —	$ —	$(6,563)	$159,437

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

Table of Contents

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

	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$61,726	$56,707
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (includes amortization of deferred debt issuance costs)	18,569	16,350
Loss (gain) on sale of assets and insurance recoveries	13	(207)
Changes in fair value of contingent consideration	344	—
Provision for doubtful accounts	1,033	(72)
Non-cash unit-based compensation	244	1,932
Other	47	—
Deferred income taxes	632	1,559
Changes in assets and liabilities:		
Accounts receivable	131,353	102,678
Inventories	156,510	163,945
Other assets	28,124	18,488
Fair value of commodity derivative instruments	(59,522)	(41,194)
Due to General Partner and affiliates	(3,428)	(5,289)
Accounts payable, accrued liabilities and other	(130,313)	(91,537)
Net cash provided by operating activities	205,332	223,360
Cash flows from investing activities		
Purchases of property, plant and equipment	(9,298)	(19,118)
Business acquisitions	—	(72,182)
Proceeds from property insurance settlement and sale of assets	43	863
Net cash used in investing activities	(9,255)	(90,437)
Cash flows from financing activities		
Net borrowings (payments) under credit agreements	(155,468)	(97,946)
Payments on capital leases, term debt, and other obligations	(1,911)	(765)
Debt issue costs	(182)	(3,858)
Distributions to unitholders	(34,166)	(27,859)
Foreign exchange on capital lease obligations	(26)	—
Repurchased units withheld for employee tax obligations	(2,508)	(1,587)
Net cash used in financing activities	(194,261)	(132,015)
Effect of exchange rate changes on cash balances held in foreign currencies	(24)	58
Net change in cash and cash equivalents	1,792	966
Cash and cash equivalents, beginning of period	6,815	2,682
Cash and cash equivalents, end of period	$8,607	$3,648
Supplemental disclosure of cash flow information		
Cash paid for interest	$17,555	$11,799
Cash paid for taxes	$2,961	$1,500
Non-cash consideration related to acquisition:		
Common units issued - Carbo	$—	$31,401
Deferred consideration obligation - Carbo	$—	$27,284

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

Table of Contents

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 by Sprague Holdings and its General Partner and engages in the purchase, storage, distribution and sale of refined products and natural gas, and 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" or the "Sponsor" 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 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 and gasoline - 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. 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.
- The other operations segment includes the purchase and distribution of coal, certain commercial trucking activities and a heating equipment service business.

See Note 2 "Revenue" for a description of our revenue activities within these business segments.

Prior to February 16, 2017, Sprague Holdings owned, directly or indirectly, all of the Partnership's subordinated units. The principal difference between the Partnership's common units and subordinated units is that during the subordination period, the common units had the right to receive a minimum quarterly distribution of $0.4125 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of cash from distributable cash flow may be made on the subordinated units. On February 16, 2017, based upon meeting certain distribution and performance tests provided in the Partnership's partnership agreement, all 10,071,970 subordinated units outstanding converted to common units on a one-for-one basis.

As of June 30, 2018, the Parent, through its ownership of Sprague Holdings, owned 12,106,348 common units representing 53% 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 50.0%, 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 partner units that it owns. See Notes 12 and 13.

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

6

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, 2017 as filed with the SEC on March 14, 2018 (the “2017 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 net sales and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are asset and liability valuations as part of an acquisition, the fair value of derivative assets and liabilities, valuation of contingent consideration, valuation of reporting units within the goodwill impairment assessment, and if necessary long-lived asset impairments and environmental and legal obligations.

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 June 30, 2018 and December 31, 2017, the consolidated results of operations for the three and six months ended June 30, 2018 and 2017, and the consolidated cash flows for the six months ended June 30, 2018 and 2017. 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.

Significant Accounting Policies

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 2017 Annual Report and are the same as are used in preparing these unaudited interim Condensed Consolidated Financial Statements except for the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) which the Partnership adopted as of January 1, 2018. The adoption of Topic 606 is discussed further in Recent Accounting Pronouncements below as well as in Note 2 "Revenue".

Recent Accounting Pronouncements

In July 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities. The objective of the guidance is to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Partnership is currently evaluating the impact of this new standard on the consolidated financial statements.

In January 2017, the FASB issued ASU 2017-04 Intangibles - Goodwill and Other (Topic 350): Simplifying the Accounting for Goodwill Impairment. The guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. The standard will be applied prospectively, and is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for any impairment tests performed after January 1, 2017.

In January 2017, the FASB issued ASU 2017-01 Business Combinations (Topic 805), which clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership will follow this new guidance for transactions entered into after December 31, 2017.

In August 2016, the FASB issued ASU 2016-15 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. The adoption of this guidance in 2018 did not have an impact on the Partnership's consolidated statements of cash flows.

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. This ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In June 2018, the FASB issued ASU 2018-11 that introduced a transition option, that the Partnership intends to adopt, that will allow the new standard to be adopted without revising comparative period reporting or disclosures. The Partnership has started the process of gathering and analyzing its lease contracts and is in the process of evaluating changes to business processes, systems and controls needed to support recognition and disclosure under this new standard. While the adoption of this new standard is expected to result in an increase to reported assets and liabilities, the Partnership has not yet determined the full impact that the adoption of ASU 2016-02 will have on its consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, 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 issued several ASUs after ASU 2014-09 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. The adoption of this standard in 2018 did not have an impact on the Partnership's consolidated financial statements nor result in significant changes to business processes, systems, or internal controls.

2. Revenue

Accounting Policies

Revenue is recognized when performance obligations under the terms of a contract with a customer are satisfied. The majority of the Partnership’s revenue is generated from refined products and natural gas contracts that have a single performance obligation which is the delivery of the related energy product. Accordingly, the Partnership recognizes revenue for refined products and natural gas when title and risk of loss have been transferred to the customer which is generally at the time of shipment or delivery of products. Revenue for the Partnership’s materials handling segment is recorded on a straight-line basis under leasing arrangements or as services are performed.

Revenue is measured as the amount of consideration the Partnership expects to receive in exchange for transferring products or providing services and is generally based upon a negotiated index, formula, list or fixed price. An allowance for doubtful accounts is recorded to reflect an estimate of the ultimate realization of the Partnership's accounts receivable and includes an assessment of the customers’ creditworthiness and the probability of collection. Estimated discounts are included in the transaction price of the contracts with customers as a reduction to net sales. The Partnership sells its products or provides its services directly to commercial customers and wholesale distributors generally under agreements with payment terms typically less than 30 days.

The Partnership has elected to account for shipping and handling as activities to fulfill the promise to transfer the good. As such, shipping and handling fees billed to customers in a sales transaction are recorded in net sales and shipping and handling costs incurred are recorded in cost of products sold (exclusive of depreciation and amortization). The Partnership has elected to exclude from net sales any value add, sales and other taxes which it collects concurrent with revenue-producing activities. These accounting policy elections are consistent with the way the Partnership historically recorded shipping and handling fees and taxes.

The majority of the Partnership's revenue is derived from contracts (i) with an original expected length of one year or less and (ii) contracts for which it recognizes revenue at the amount in which it has the right to invoice the customer as product is delivered. The Partnership has elected the practical expedient not to disclose the value of remaining performance obligations associated with these types of contracts.

Contract Balances

Contract liabilities primarily relate to advances or deposits received from the Partnership's customers before revenue is recognized. These amounts are included in accrued liabilities in the Condensed Consolidated Balance Sheets and amounted to $6.3 million and $7.7 million as of June 30, 2018 and December 31, 2017, respectively. A substantial portion of the contract liabilities as of December 31, 2017 remains outstanding as of June 30, 2018 as they are primarily deposits. The Partnership does not have any material contract assets as of June 30, 2018 or December 31, 2017.

Table of Contents

Disaggregated Revenue

In general, the Partnership's business segmentation is aligned according to the nature and economic characteristics of its products and customer relationships which provides meaningful disaggregation of each business segment's results of operations. The Partnership operates its businesses in the Northeast and Mid-Atlantic United States and Eastern Canada.

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. Refined products revenue-producing activities are direct sales to customers including throughput and exchange transactions. Revenue is recognized when the product is delivered. Revenue is not recognized on exchange agreements, which are entered into primarily to acquire refined products by taking delivery of products closer to the Partnership's end markets. Net differentials or fees for exchange agreements are recorded within cost of products sold (exclusive of depreciation and amortization).

The natural gas segment purchases, sells and distributes natural gas to commercial and industrial customers. The Partnership purchases the natural gas it sells from natural gas producers and trading companies. Natural gas revenue-producing activities are sales to customers at various points on natural gas pipelines or at local distribution companies (i.e., utilities). Natural gas sales not billed by month-end are accrued based upon gas volumes delivered.

The materials handling segment offloads, stores and prepares for delivery a variety of customer-owned products. A majority of the materials handling segment revenue is generated under leasing arrangements with revenue recorded over the lease term generally on a straight-line basis. Contingent rentals are recorded as revenue only when billable under the arrangement. For materials handling contracts that are not leases, the Partnership recognizes revenue either at a point in time as services are performed or over a period of time if the services are performed in a continuous fashion over the period of the contract.
The other operations segment includes the purchase and distribution of coal, certain commercial trucking activities and a heating equipment service business. Revenue from other activities is recognized when the product is delivered or the services are rendered.

Further disaggregation of net sales by business segment and geographic destination is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net sales:				
Refined products				
Distillates	$505,863	$307,732	$1,487,554	$938,485
Gasoline	87,959	67,004	164,316	136,698
Heavy fuel oil and asphalt	70,203	56,248	193,015	137,391
Total refined products	$664,025	$430,984	$1,844,885	$1,212,574
Natural gas	58,428	65,708	188,355	185,374
Materials handling	14,218	12,798	27,366	22,723
Other operations	4,985	4,136	12,198	10,762
Net sales	$741,656	$513,626	$2,072,804	$1,431,433
Net sales by Country:				
United States	$670,903	$455,306	$1,936,445	$1,326,881
Canada	$70,753	$58,320	$136,359	104,552

Net sales	$741,656	$513,626	$2,072,804	$1,431,433

9

Table of Contents

3. Business Combinations

The Partnership completed five business acquisitions during the year ended December 31, 2017 as described below. Allocations of the purchase price to the assets acquired and liabilities assumed have been made to record, where applicable, inventory, derivative assets and liabilities, natural gas transportation assets and liabilities, property, plant and equipment, identifiable intangible assets such as customer relationships and non-compete agreements as well as goodwill. If the results of these businesses had been included in the consolidated results of the Partnership for the entire three and six months ended June 30, 2017, unaudited consolidated pro forma net sales would have been $539.2 million and $1,511.0 million, respectively, while the unaudited pro forma net (loss) income for the three months and six months ended June 30, 2017 would not have been materially different.

The Partnership recognized $0.3 million and $0.6 million of acquisition related costs during the three months ended June 30, 2018 and 2017, and $0.7 million and $1.0 million for the six months ended June 30, 2018 and 2017, respectively, which were expensed and are included in selling, general and administrative expense.

Year Ended December 31, 2017

Coen Energy

On October 1, 2017, the Partnership purchased the membership interests of Coen Energy, LLC and Coen Transport, LLC as well as assets consisting of four bulk plants and underlying real estate (collectively, “Coen Energy”). Coen Energy, located in Washington, PA, provides energy products to commercial and residential customers located in Pennsylvania, Ohio and West Virginia. The Coen Energy business also provides energy fuel services to customers that are engaged in Marcellus and Utica shale drilling operations. The Coen Energy business is supported by four in-land bulk plants, two throughput locations, approximately 100 delivery vehicles and approximately 250 employees as of December 31, 2017. Initial consideration paid was $35.3 million in cash, not including the purchase of inventory and other adjustments, which was financed with borrowings under our credit facility. Contingent consideration of up to $12.0 million is payable based on achieving certain economic performance measures during the three year period ending September 30, 2020. The operations of Coen Energy have been included in the Partnership's refined products segment since the acquisition date.

The following table summarizes the preliminary fair values of the assets acquired and liabilities assumed at the acquisition date:

Inventories	$567
Other current assets	115
Property, plant and equipment	12,972
Intangibles	18,375
Total identifiable assets acquired	32,029
Other liabilities	(256)
Net identifiable assets acquired	31,773
Goodwill	13,095
Net assets acquired	$44,868

The goodwill recognized is primarily attributable to Coen Energy’s reputation in its geographic market area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate.

Carbo Terminals

On April 18, 2017, the Partnership acquired substantially all of the assets of Carbo Industries, Inc. and certain of its affiliates (together “Carbo”) by purchasing Carbo's Inwood and Lawrence, New York refined product terminal assets and its associated wholesale distribution business. The fair value of the consideration totaled $72.0 million and consisted of $13.3 million in cash that was financed through borrowings under the Credit Agreement, an obligation to pay $38.2 million over a ten year period (estimated net present value of $27.3 million) and $31.4 million in unregistered common units. The Carbo terminals have a combined gasoline, ethanol and distillate storage capacity of 174,000 barrels and are supplied primarily by pipeline with the ability to also accept product deliveries by barge and truck. The operations of Carbo are included in the Partnership's refined products segment since the acquisition date.

Table of Contents

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

Inventories	$3,220
Derivative and other current assets	111
Property, plant and equipment	22,995
Intangibles	29,000
Total identifiable assets acquired	55,326
Other liabilities	(188)
Net identifiable assets acquired	55,138
Goodwill	16,718
Net assets acquired	$71,856

The goodwill recognized is primarily attributable to Carbo's reputation in the New York City area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate.

Capital Terminal

On February 10, 2017, the Partnership purchased the East Providence, Rhode Island refined product terminal business of Capital Properties Inc. (the "Capital Terminal"). Consideration paid was $22.0 million and was financed with borrowings under the Credit Agreement. The terminal's distillate storage capacity of 1.0 million barrels had been leased by the Partnership since April 2014 and was previously included in the Partnership's total storage capacity. The operations of the Capital Terminal are included in the Partnership's refined products segment since the acquisition date.

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

Property, plant and equipment	$21,960
Accrued liabilities and other, net	(22)
Net assets acquired	$21,938

Global Natural Gas & Power

On February 1, 2017, the Partnership purchased the natural gas marketing and electricity brokering business of Global Partners LP ("Global Natural Gas & Power") for $17.3 million, not including the purchase of natural gas inventory, assumption of derivative assets (liabilities) and other adjustments. Consideration paid was $16.3 million and was financed with borrowings under the Credit Agreement. This business markets natural gas and electricity to commercial, industrial, municipal and institutional customer locations in the Northeast United States. The operations of Global Natural Gas & Power are included in the Partnership's natural gas segment since the acquisition date.

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

Inventory	$286
Derivative assets	5,873
Natural gas transportation assets	695
Derivative assets long term	1,089
Natural gas transportation assets long term	378
Intangibles	5,046
Total identifiable assets acquired	13,367
Derivative liabilities	(4,865)
Natural gas transportation liabilities	(465)
Derivative liabilities long term	(1,214)
Natural gas transportation liabilities long term	(162)
Net identifiable assets acquired	6,661
Goodwill	9,592
Net assets acquired	$16,253

Table of Contents

The goodwill recognized is primarily attributable to Global Natural Gas & Power's reputation in its market regions, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate.

L.E. Belcher Terminal

On February 1, 2017, the Partnership purchased the Springfield, Massachusetts refined product terminal assets of Leonard E. Belcher, Incorporated ("L.E. Belcher") for approximately $20.0 million, not including the purchase of inventory, assumption of derivative assets (liabilities) and other adjustments. Consideration paid was $20.7 million and was financed with borrowings under the Credit Agreement. The purchase consists of two pipeline-supplied distillate terminals and one distillate storage facility with a combined capacity of 283,000 barrels, as well as L.E. Belcher's associated wholesale and commercial fuels businesses. The operations of L.E. Belcher are included in the Partnership's refined products segment since the acquisition date.

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

Inventories	$632
Derivative and other current assets	658
Property, plant and equipment	9,152
Intangibles	5,800
Total identifiable assets acquired	16,242
Derivative and other current liabilities	(680)
Net identifiable assets acquired	15,562
Goodwill	5,081
Net assets acquired	$20,643

The goodwill recognized is primarily attributable to L.E. Belcher's reputation in the Springfield, Massachusetts area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate.

4. Accumulated Other Comprehensive Loss, Net of Tax

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

	June 30, 2018	December 31, 2017
Fair value of interest rate swaps, net of tax	$5,022	$ 2,588
Cumulative foreign currency translation adjustment	(11,585)	(11,458)
Accumulated other comprehensive loss, net of tax	$(6,563)	$ (8,870)

5. Inventories

	June 30, 2018	December 31, 2017
Petroleum and related products	$173,257	$324,491
Asphalt	2,023	5,221
Coal	2,643	3,712
Natural gas	1,427	2,435
Inventories	$179,350	$335,859

Table of Contents

6. Credit Agreement

	June 30, 2018	December 31, 2017
Working capital facilities	$190,383	$ 341,850
Acquisition facility	379,100	383,500
Total credit agreement	569,483	725,350
Less: current portion of working capital facilities	(57,248)	(275,613)
Long-term portion	$512,235	$ 449,737

Sprague Operating Resources LLC and Kildair Service ULC ("Kildair"), wholly owned subsidiaries of the Partnership, are borrowers under an amended and restated revolving credit agreement that matures on April 27, 2021 (the "Credit Agreement"). Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

As of June 30, 2018, the revolving credit facilities under the Credit Agreement contained, among other items, the following:

- A U.S. dollar revolving working capital facility of up to $950.0 million, subject to borrowing base limits, to be used for working capital loans and letters of credit;
- A multicurrency revolving working capital facility of up to $100.0 million, subject to borrowing base limits, to be used for working capital loans and letters of credit;
- Revolving acquisition facility of up to $550.0 million, subject to acquisition facility borrowing base limits, 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 including the receipt of additional commitments from lenders, the ability to increase the U.S. dollar revolving working capital facility by $250.0 million and the multicurrency revolving working capital facility by $220.0 million subject to a maximum combined increase for both facilities of $270.0 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 bears interest, at the borrowers’ option, at a rate per annum equal to either (i) 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 (ii) an alternate rate plus a specified margin.

For loans denominated in U.S. dollars, the alternate rate is the Base Rate which is the highest of (a) the U.S. Prime Rate as in effect from time to time, (b) the greater of the Federal Funds Effective Rate and the Overnight Bank Funding 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 loans denominated in Canadian dollars, 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 June 30, 2018 and December 31, 2017, had a borrowing base of $341.5 million and $623.2 million, respectively. As of June 30, 2018 and December 31, 2017, outstanding letters of credit were $18.6 million and $72.3 million, respectively. As of June 30, 2018, excess availability under the working capital facilities was $132.5 million and excess availability under the acquisition facilities was $170.9 million.

The weighted average interest rate was 4.8% and 4.2% at June 30, 2018 and December 31, 2017, respectively. No amounts are due under the Credit Agreement until the maturity date, however, the current portion of the Credit Agreement at June 30, 2018 and December 31, 2017 represents the amounts of the working capital facility intended to be repaid during the following twelve month period.

13

The Credit Agreement contains certain restrictions and covenants among which include 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 June 30, 2018, the Partnership was in compliance with these covenants.

7. 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 $28.0 million and $20.7 million for the three months ended June 30, 2018 and 2017, and $62.9 million and $48.2 million for the six months ended June 30, 2018 and 2017, respectively. Through the General Partner, the Partnership also participates in the Parent's pension and other post-retirement benefits. At June 30, 2018 and December 31, 2017, total amounts due to the General Partner with respect to these benefits and overhead costs were $9.4 million and $12.9 million, respectively.

8. Segment Reporting

The Partnership has four reporting segments that comprise the structure used by the chief operating decision makers (CEO and CFO/COO) to make key operating decisions and assess performance. When establishing a reporting segment, the Partnership aggregates individual operating units that are in the same line of business and have similar economic characteristics such as adjusted gross margin. These reporting segments are refined products, natural gas, materials handling and other activities.

The Partnership's refined products reporting 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, drill sites, large industrial companies, real estate management companies, hospitals and educational institutions. The refined products reporting segment consists of three operating segments.

The Partnership's natural gas reporting 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 natural gas reporting segment consists of one operating segment.

The Partnership's materials handling reporting 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 generally provided under multi-year agreements as either fee-based activities or as leasing arrangements when the right to use an identified asset (such as storage tanks or storage locations) has been conveyed in the agreement. The materials handling reporting segment consists of two operating segments.

The Partnership's other reporting segment includes 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. The other activities reporting segment consists of two operating segments.

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 six months ended June 30, 2018 and 2017, respectively. The Partnership's foreign sales, primarily sales of refined products, asphalt and natural gas to its customers in Canada, were $70.8 million and $58.3 million for the three months ended June 30, 2018 and 2017, and $136.4 million and $104.6 million for the six months ended June 30, 2018 and 2017, respectively.

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net sales:				
Refined products	$664,025	$430,984	$1,844,885	$1,212,574
Natural gas	58,428	65,708	188,355	185,374
Materials handling	14,218	12,798	27,366	22,723
Other operations	4,985	4,136	12,198	10,762
Net sales	$741,656	$513,626	$2,072,804	$1,431,433
Adjusted gross margin (1):				
Refined products	$28,671	$23,815	$85,006	$63,293
Natural gas	5,055	2,568	43,003	41,158
Materials handling	14,269	12,798	27,417	22,723
Other operations	1,675	1,530	3,781	3,903
Adjusted gross margin	49,670	40,711	159,207	131,077
Reconciliation to operating (loss) income (2):				
Add: unrealized (loss) gain on inventory derivatives (3)	(971)	4,539	22,590	29,047
Add: unrealized gain on prepaid forward contract derivatives (4)	—	267	—	240
Add: unrealized (loss) gain on natural gas transportation contracts (5)	(3,716)	(949)	10,352	6,865
Operating costs and expenses not allocated to operating segments:				
Operating expenses	(22,281)	(16,901)	(45,490)	(33,733)
Selling, general and administrative	(18,562)	(19,624)	(46,426)	(45,913)
Depreciation and amortization	(8,378)	(6,950)	(16,803)	(12,882)
Operating (loss) income	(4,238)	1,093	83,430	74,701
Other income	—	119	—	183
Interest income	169	88	281	172
Interest expense	(9,412)	(8,279)	(19,296)	(15,434)
Income tax benefit (provision)	286	(813)	(2,689)	(2,915)
Net (loss) income	$(13,195)	$(7,792)	$61,726	$56,707

(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 derivatives, prepaid forward contract derivatives and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income. 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. 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 net realizable value. 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.

(4) The unrealized hedging gain (loss) on prepaid forward contract derivatives represents the Partnership's estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income 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 and changes in the fair value are therefore not included in net income. 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 prepaid forward contract appreciates or declines, which creates unrealized hedging gains (losses) that are included in net income.

Table of Contents

(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 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 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.

As of June 30, 2018, goodwill recorded for the refined products, natural gas, materials handling and other operations segments amounted to $71.4 million, $35.5 million, $6.9 million and $1.2 million, respectively.

9. Financial Instruments and Off-Balance Sheet Risk

As of June 30, 2018 and December 31, 2017, the carrying amounts of cash, cash equivalents and accounts receivable approximated fair value because of the short maturity of these instruments. As of June 30, 2018 and December 31, 2017, 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 June 30, 2018 and December 31, 2017, the carrying value of the Partnership's debt approximated fair value due to the variable interest nature of these instruments.

The Partnership's deferred consideration was recorded in connection with an acquisition on April 18, 2017 using an estimated fair value discount at the time of the transaction. As of June 30, 2018, the carrying value of the deferred consideration approximated fair value due to the fact that there has been no significant subsequent change in the estimated fair value discount rate.

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

	As of June 30, 2018			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Derivative assets:				
Commodity fixed forwards	$18,426	$—	$ 18,426	$ —
Commodity swaps and options	36,616	36,612	4	—
Commodity derivatives	55,042	36,612	18,430	—
Interest rate swaps	5,311	—	5,311	—
Total derivative assets	$60,353	$36,612	$ 23,741	$ —
Derivative liabilities:				
Commodity exchange contracts	$7	$7	$ —	$ —
Commodity fixed forwards	22,692	—	22,692	—
Commodity swaps and options	25,658	25,641	17	—
Commodity derivatives	48,357	25,648	22,709	—
Interest rate swaps	250	—	250	—
Other	52	—	52	—
Total derivative liabilities	$48,659	$25,648	$ 23,011	$ —
Contingent consideration	$10,069	$—	$ —	$ 10,069

Table of Contents

	As of December 31, 2017			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Derivative assets:				
Commodity fixed forwards	$11,502	$—	$ 11,502	$ —
Commodity swaps and options	100,630	100,613	17	—
Commodity derivatives	112,132	100,613	11,519	—
Interest rate swaps	2,615	—	2,615	—
Total derivative assets	$114,747	$100,613	$ 14,134	$ —
Derivative liabilities:				
Commodity fixed forwards	$61,195	$—	$ 61,195	$ —
Commodity swaps and options	103,827	103,654	173	—
Commodity derivatives	165,022	103,654	61,368	—
Interest rate swaps	6	—	6	—
Total derivative liabilities	$165,028	$103,654	$ 61,374	$ —
Contingent consideration	$9,725	$—	$ —	$ 9,725

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 June 30, 2018 will settle prior to December 31, 2019.

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.

Table of Contents

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 utilizes fair value measurements based on Level 3 inputs for its contingent consideration liability.
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 June 30, 2018 and December 31, 2017.

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 $33.6 million at June 30, 2018. Information related to these offsetting arrangements is set forth below:

	As of June 30, 2018			
		Gross Amount Not Offset in the Balance Sheet		
	Gross Amount of Assets/Liabilities in the Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$55,042	$ (26,797)	$ —	$ 28,245
Interest rate swap derivative assets	5,311	—	—	5,311
Fair value of derivative assets	$60,353	$ (26,797)	$ —	$ 33,556
Commodity derivative liabilities	$(48,357)	$ 26,797	$ 6,685	$ (14,875)
Interest rate swap derivative liabilities	(250)	—	—	(250)
Other	(52)	—	—	(52)
Fair value of derivative liabilities	$(48,659)	$ 26,797	$ 6,685	$ (15,177)

	As of December 31, 2017			
		Gross Amount Not Offset in the Balance Sheet		
	Gross Amount of Assets/Liabilities in the Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount

Commodity derivative assets	$112,132	$ (86,493)	$ (4,303)	$ 21,336
Interest rate swap derivative assets	2,615	—	—	2,615
Fair value of derivative assets	$114,747	$ (86,493)	$ (4,303)	$ 23,951
Commodity derivative liabilities	$(165,022)	$ 86,493	$ 20,975	$ (57,554)
Interest rate swap derivative liabilities	(6)	—	—	(6)
Fair value of derivative liabilities	$(165,028)	$ 86,493	$ 20,975	$ (57,560)

Table of Contents

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Refined products contracts	$(1,227)	$11,351	$8,976	$44,918
Natural gas contracts	(3,832)	(406)	(2,960)	14,758
Total	$(5,059)	$10,945	$6,016	$59,676

There were no discretionary trading activities for the three and six months ended June 30, 2018 and 2017. The following table presents gross volume of commodity derivative instruments outstanding for the periods indicated:

	As of June 30, 2018		As of December 31, 2017	
	Refined Products (Barrels)	Natural Gas (MMBTUs)	Refined Products (Barrels)	Natural Gas (MMBTUs)
Long contracts	4,469	121,484	9,255	133,532
Short contracts	(6,444)	(67,723)	(13,487)	(72,074)

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 June 30, 2018 were as follows:

Beginning	Ending	Notional Amount
January 2018	January 2019	$275,000
January 2019	January 2020	$300,000
January 2020	January 2021	$300,000
January 2021	January 2022	$300,000
January 2022	January 2023	$250,000

There was no material ineffectiveness determined for the cash flow hedges for the three and six months ended June 30, 2018 and 2017.

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 June 30, 2018, the amount of unrealized gains, net of tax, expected to be reclassified to earnings during the following twelve-month period was $1.9 million.

Contingent Consideration

As part of the Coen Energy acquisition in 2017, the Partnership may be obligated to pay contingent consideration of up to $12.0 million if certain earnings objectives during the first three years following the acquisition are met. The estimated fair value of the contingent consideration arrangement is classified within Level 3 and was determined using an income approach based on probability-weighted discounted cash flows. Under this method, a set of discrete potential future earnings was determined using internal estimates based on various revenue growth rate assumptions for each scenario. A probability was assigned to each discrete potential future earnings estimate. The resulting probability-weighted contingent consideration amounts were discounted using a weighted average discount rate of 7.0%. Changes in either the revenue growth rates, related earnings or the discount rate could result in a material change to the amount of contingent consideration accrued and such changes will be recorded in the Partnership's condensed consolidated statements of operations.

Table of Contents

The Partnership records changes in the estimated fair value of the contingent consideration within selling, general and administrative expenses in the condensed consolidated statements of operations. Changes in the contingent consideration liability are measured at fair value on a recurring basis using unobservable inputs (Level 3) and during fiscal 2018 are as follows:

Contingent consideration - December 31, 2017	$9,725
Change in estimated fair value	344
Contingent consideration - June 30, 2018	$10,069

10. Commitments and Contingencies

Legal, Environmental and Other Proceedings

The Partnership is subject to a tax on product it imports into Canada. During a recent audit of the annual filings, the Partnership initiated legal action seeking a declaration to limit the applicability of the tax to direct imports, as well as the periods subject to review. After filing legal action, the Partnership was assessed $3.0 million of tax, including interest and penalties, for the period of 2013 to 2016, and information for the years dating back to 2007 has been requested. The Partnership has accrued an amount which it believes to be a reasonable estimate of the low end of a range of loss related to this matter and such amount is not material to the consolidated financial statements.

The Partnership is involved in other various lawsuits, 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.

11. Equity and Equity-Based Compensation

Equity Awards - Performance-based Phantom Units

The board of directors of the General Partner grants performance-based phantom unit awards to key employees that vest at the end of a performance period (generally three years). 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.

OCF-based Phantom Units

Phantom unit awards granted in 2018, 2017 and 2016 include a performance criteria that considers Sprague Holdings operating cash flow, as defined ("OCF"), over a three year performance 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 is 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.

Distribution Equivalent Rights

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.

Table of Contents

A summary of the Partnership's unit awards subject to vesting during the six months ended June 30, 2018 is set forth below:

	2018 Awards		2017 Awards		2016 Awards	
	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, 2017	—	$ —	131,000	$ 26.62	163,900	$ 17.52
Granted	143,981	23.30	—	—	—	—
Forfeited	—	—	—	—	—	—
Vested	—	—	—	—	—	—
Nonvested at June 30, 2018	143,981	$ 23.30	131,000	$ 26.62	163,900	$ 17.52

During the three-months ended June 30, 2018, the Partnership reduced its estimate of the number of units expected to vest over the vesting period and as a result unit-based compensation for the three and six months ended June 30, 2018 was $(0.6) million and $0.2 million, respectively, as compared to $1.0 million and $1.9 million, for the three and six months ended June 30, 2017. Unit-based compensation is included in selling, general and administrative expenses. Unrecognized compensation cost related to performance-based phantom unit awards totaled $5.4 million as of June 30, 2018 which is expected to be recognized over a weighted average period of 17 months.

Equity - Changes in Partnership Units

Phantom units with a performance period ended as of December 31, 2017 vested at the 195.5% level and as a result 271,748 common units (vested market value of $7.0 million) were issued during January 2018, with 97,351 units being withheld to satisfy tax withholding requirements.

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, 2016	9,207,473	2,034,378	10,071,970
Conversion of subordinated units	—	10,071,970	(10,071,970)
Units issued in connection with performance awards	89,315	—	—
Units issued in connection with employee bonus	8,840	—	—
Director vested awards	9,360	—	—
Units issued in connection with Carbo acquisition	1,131,551	—	—
Balance as of December 31, 2017	10,446,539	12,106,348	—
Units issued in connection with performance awards	174,397	—	—
Balance as of June 30, 2018	10,620,936	12,106,348	—

12. Earnings Per Unit

The Partnership has identified the IDRs as participating securities and uses the two-class method when calculating the net income per unit applicable to limited partners, Earnings per unit applicable to limited partners 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. Diluted earnings per unit includes the effects of potentially dilutive units on the Partnership's common units, consisting of unvested phantom units.

21

Table of Contents

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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Weighted average limited partner common units - basic	22,727,284	22,319,704	22,726,320	21,864,875
Dilutive effect of unvested phantom units	—	—	58,016	335,195
Weighted average limited partner common units - dilutive	22,727,284	22,319,704	22,784,336	22,200,070

13. Partnership Distributions

The Partnership's partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders will receive. Payments made in connection with DERs are recorded as a distribution.

Cash distributions for the periods indicated were as follows:

Three Months Ended	Payment Date	Per Unit	Common	IDR	DER	Total
December 31, 2017	February 12, 2018	$0.6375	$ 14,489	$ 1,373	$ 1,760	$ 17,622
March 31, 2018	May 18, 2018	$0.6525	$ 14,830	$ 1,714	$ —	$ 16,544

In addition, on July 26, 2018, the Partnership declared a cash distribution for the three months ended June 30, 2018, of $0.6675 per unit, totaling $17.2 million (including a $2.1 million IDR distribution). Such distributions are to be paid on August 10, 2018, to unitholders of record on August 6, 2018.

Table of Contents

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; and, (x) our ability to successfully complete our organic growth and acquisition projects and/or to realize the anticipated financial and operational 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, 2017, as filed with the U.S. Securities and Exchange Commission (“SEC”) on March 14, 2018 (the “2017 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”. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Quarterly Report may not occur.

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.

Table of Contents

Overview

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our General Partner. We engage in the purchase, storage, distribution and sale of refined products and natural gas, and provide storage and handling services for a broad range of materials. Our limited partnership units representing limited partner interests are listed on the New York Stock Exchange ("NYSE") under the ticker symbol “SRLP". As used in this Quarterly Report, unless otherwise indicated, "Sprague",“we,” “us,” “our” mean Sprague Resources LP and, where the context requires, includes our subsidiaries.

Our Predecessor was founded in 1870 as the Charles H. Sprague Company in Boston, Massachusetts; and, in 1905, the company opened the Penobscot Coal and Wharf Company, a tidewater terminal located in Searsport, Maine. By World War II, the company was operating eleven terminals and a fleet of two dozen vessels transporting coal and other products throughout the world. As fuel needs diversified in the United States, the company expanded its product offerings and invested in terminals, tankers, and product handing activities. In 1959, the company expanded its oil marketing activities via entry into the distillate oil market. In 1970, the company was sold to Royal Dutch Shell’s Asiatic Petroleum subsidiary; and, in 1972, Royal Dutch Shell sold the company to Axel Johnson Inc. a member of the Axel Johnson Group of Stockholm, Sweden.

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 refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of 14.7 million barrels for refined products and other liquid materials, as well as 2.0 million square feet of materials handling capacity. Furthermore, we have access to more than 40 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. See Note 8 “Segment Reporting” to our Condensed Consolidated Financial Statements for a presentation of financial results by reportable segment and see Part I, Item 2 "Management’s Discussion and Analysis of Financial Condition and Results of Operation—Results of Operation” for a discussion of financial results by 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, asphalt paving companies. In addition, as a result of our recent acquisition of Coen Energy, our customers include businesses engaged in the development of natural gas resources in Pennsylvania and surrounding states.

In our natural gas segment we purchase, sell and distribute natural gas to approximately 15,000 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.

Our materials handling segment is generally conducted under multi-year agreements as either fee-based activities or as leasing arrangements when the right to use an identified asset (such as storage tanks or storage locations) has been conveyed in the agreement. 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. Historically, a majority of our materials handling activity has generated qualified income.

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.

Table of Contents

As of June 30, 2018, our Sponsor, through its ownership of Sprague Holdings, owns 12,106,348 common units representing an aggregate of 53% 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") which entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from distributable cash flow in excess of $0.474375 per unit per quarter. The maximum IDR distribution of 50.0% does not include any distributions that Sprague Holdings may receive on any limited partner units that it owns.

2017 Acquisitions

Coen Energy Acquisition

On October 1, 2017, we purchased the membership interests of Coen Energy, LLC and Coen Transport, LLC as well as assets consisting of four bulk plants and underlying real estate (collectively, "Coen Energy"). Coen Energy, located in Washington, PA, provides energy products to commercial and residential customers located in Pennsylvania, Ohio and West Virginia. The Coen Energy business also provides fuel and delivery services to customers that are engaged in Marcellus and Utica shale drilling operations. The Coen Energy business is supported by four in-land bulk plants, two throughput locations, approximately 100 delivery vehicles and approximately 250 employees as of December 31, 2017. Initial consideration paid was $35.3 million in cash, not including the purchase of inventory and other adjustments, which was financed with borrowings under our credit facility. Contingent consideration of up to $12 million is payable based on achieving certain economic performance measures during the three year period ending September 30, 2020.

Carbo Terminals Acquisition

On April 18, 2017, we acquired substantially all of the assets of Carbo Industries, Inc. and certain of its affiliates (together "Carbo") by purchasing Carbo's Inwood and Lawrence, New York refined product terminal assets and its associated wholesale distribution business. The fair value of the consideration totaled $72.0 million and consisted of $13.3 million in cash that was financed through borrowings under our credit facility, an obligation to pay $38.2 million over a ten year period (estimated net present value of $27.3 million) and 1,131,551 common units with a fair value at $31.4 million as of April 18, 2017. The Carbo terminals are primarily supplied by pipeline and have a combined gasoline, ethanol and distillate storage capacity of 174,000 barrels.

Capital Terminal Acquisition

On February 10, 2017, we acquired the East Providence, Rhode Island refined product terminal of Capital Terminal Company (the "Capital Terminal") for $22.0 million which we financed with borrowings under our credit facility. The terminal's combined distillate storage capacity of just over 1.0 million barrels had been leased by us since April 2014 and was previously included in our total storage capacity.

In conjunction with this acquisition, we undertook an expansion capital project to convert half of the terminal's storage capacity to gasoline and ethanol service to support a new ten year fee-for-service gasoline storage and handling agreement with a major East Coast gasoline marketer and another project to optimize distillate storage between this newly acquired terminal and our existing terminal facility in Providence to allow for expanded materials handling capability. Both projects were completed prior to December 31, 2017 at a total cost of approximately $16 million.

Global Natural Gas & Power Acquisition

On February 1, 2017, we purchased the natural gas marketing and electricity brokering business of Global Partners LP ("Global Natural Gas & Power") for $17.3 million, not including the purchase of natural gas inventory, assumption of derivative liabilities and other adjustments. Consideration paid was $16.3 million and was financed with borrowings under our credit facility. The business serves approximately 4,000 commercial, industrial, municipal and institutional customer locations in the Northeast United States with approximately 8 billion cubic feet of natural gas and 1 billion kWh of electricity annually.

L.E. Belcher Terminal Acquisition

On February 1, 2017, we purchased the Springfield, Massachusetts refined product terminal assets of Leonard E. Belcher, Incorporated (“L.E. Belcher”) for $20.0 million in cash, not including the purchase of inventory and other adjustments. Consideration paid was $20.7 million and was financed with borrowings under our credit facility. The purchase consists of two pipeline-supplied distillate terminals and one distillate storage facility with a combined capacity of 283,000 barrels, as well as L.E. Belcher’s associated wholesale and commercial fuels businesses.

Table of Contents

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 EBITDA and adjusted gross margin, (2) operating expenses, (3) selling, general and administrative expenses and (4) heating degree days.

Non-GAAP Financial Measures

We present the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin in this Quarterly Report as described below. We present the non-GAAP financial measures maintenance capital expenditures and expansion capital expenditures in this Quarterly Report as described below in "Liquidity and Capital Resources - Capital Expenditures".

EBITDA and Adjusted EBITDA

Management believes that adjusted EBITDA is an aid in assessing repeatable operating performance that is not distorted by non-recurring items or market volatility, the viability of acquisitions and capital expenditure projects and 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 unitholders.

We define EBITDA as net income (loss) before interest, income taxes, depreciation and amortization. We define adjusted EBITDA as EBITDA adjusted for 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), changes in fair value of contingent consideration, the net impact of biofuel excise tax credits in 2017 and 2013, and commencing in the fourth quarter of 2017, adjusted for the impact of acquisition related expenses.

EBITDA and adjusted EBITDA are used as supplemental financial measures 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 and adjusted EBITDA are not prepared in accordance with GAAP and should not be considered alternatives to net income (loss) or operating income, or any other measure of financial performance presented in accordance with GAAP. EBITDA and adjusted EBITDA exclude some, but not all, items that affect net income (loss) and operating income (loss).

The GAAP measure most directly comparable to EBITDA and adjusted EBITDA is net income (loss). EBITDA and adjusted EBITDA should not be considered as an alternative to net income (loss) or cash provided by (used in) operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. EBITDA and adjusted EBITDA are not presentations made in accordance with GAAP and have important limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP. Because EBITDA and adjusted EBITDA exclude some, but not all, items that affect net income (loss) and is defined differently by different companies, our definitions of EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We recognize that the usefulness of EBITDA and adjusted EBITDA as an evaluative tool may have certain limitations, including:

-

EBITDA and adjusted EBITDA do not include interest expense. Because we have borrowed money in order to finance our operations, interest expense is a necessary element of our costs and impacts our ability to generate profits and cash flows. Therefore, any measure that excludes interest expense may have material limitations;

- EBITDA and adjusted EBITDA do not include depreciation and amortization expense. Because capital assets, depreciation and amortization expense is a necessary element of our costs and ability to generate profits, any measure that excludes depreciation and amortization expense may have material limitations;

Table of Contents

- EBITDA and adjusted EBITDA do not include provision for income taxes. Because the payment of income taxes is a necessary element of our costs, any measure that excludes income tax expense may have material limitations;
- EBITDA and adjusted EBITDA do not reflect capital expenditures or future requirements for capital expenditures or contractual commitments;
- EBITDA and adjusted EBITDA do not reflect changes in, or cash requirements for, working capital needs; and
- EBITDA and adjusted EBITDA do not allow us to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss.

Adjusted Gross Margin

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. 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 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.

We define adjusted gross margin as net sales less cost of products sold (exclusive of depreciation and amortization) and decreased by total commodity derivative gains and losses included in net income (loss) and increased by realized commodity derivative gains and losses included in net income (loss), in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts. Adjusted gross margin has no impact on reported volumes or net sales.

Adjusted gross margin is used as a supplemental financial measure 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 is not prepared in accordance with GAAP and should not be considered as an alternative to net income (loss) or operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

We define adjusted unit gross margin as adjusted gross margin divided by units sold, as expressed in gallons for refined products and in MMBtus for natural gas.

For a reconciliation of adjusted gross margin and adjusted EBITDA to the GAAP measures most directly comparable, see the reconciliation tables included in "Results of Operations." See Note 8 "Segment Reporting" to our Condensed Consolidated Financial Statements for a presentation of our financial results by reportable segment. 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.

Table of Contents

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 to see if a month or a year was warmer or cooler than usual. For purposes of evaluating our results of operations, we use heating degree day amounts as reported by the NOAA Regional Climate Center. Prior to April 1, 2018, we reported degree day information utilizing the New England oil home heating region and for comparison purposes we used historical degree day information for the New England oil home heating region over the period of 1981-2011. Commencing April 1, 2018, we report degree day information for Boston and New York City (weighted equally) with a historical average for the same geographic locations over the previous ten-year period. We made these changes to incorporate more recent average information and to better reflect the geographic locations of our customer base. All degree day information has been revised to conform to this presentation.

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 net realizable value. 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 using daily 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 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

Table of Contents

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 2017 Annual Report for a discussion of the trends and factors that impact our business.

Results of Operations

Our current and future results of operations may not be comparable to our historical results of operations. Our results of operations may be impacted by, among other things, swings in commodity prices, primarily in refined products and natural gas, and acquisitions or dispositions. We use economic hedges to minimize the impact of changing prices on refined products and natural gas inventory. As a result, commodity price increases at the end of a year can create lower gross margins as the economic hedges, or derivatives, for such inventory may lose value, whereas an increase in the value of such inventory is disregarded for GAAP financial reporting purposes and recorded at the lower of cost or net realizable value. Please read “How Management Evaluates Our Results of Operations.” For a description of acquisition activity during the periods presented, please read Note 3 "Business Combinations" to our Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands)			
Net sales	$741,656	$513,626	$228,030	44 %
Cost of products sold (exclusive of depreciation and amortization)	696,673	469,058	227,615	49 %
Operating expenses	22,281	16,901	5,380	32 %
Selling, general and administrative	18,562	19,624	(1,062)	(5)%
Depreciation and amortization	8,378	6,950	1,428	21 %
Total operating costs and expenses	745,894	512,533	233,361	46 %
Operating (loss) income	(4,238)	1,093	(5,331)	(488)%
Other income	—	119	(119)	(100)%
Interest income	169	88	81	92 %
Interest expense	(9,412)	(8,279)	(1,133)	14 %
Loss before income taxes	(13,481)	(6,979)	(6,502)	93 %
Income tax benefit (provision)	286	(813)	1,099	(135)%
Net loss	$(13,195)	$(7,792)	$(5,403)	69 %

Table of Contents

	Six Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands)			
Net sales	$2,072,804	$1,431,433	$641,371	45 %
Cost of products sold (exclusive of depreciation and amortization)	1,880,655	1,264,204	616,451	49 %
Operating expenses	45,490	33,733	11,757	35 %
Selling, general and administrative	46,426	45,913	513	1 %
Depreciation and amortization	16,803	12,882	3,921	30 %
Total operating costs and expenses	1,989,374	1,356,732	632,642	47 %
Operating income	83,430	74,701	8,729	12 %
Other income	—	183	(183)	*
Interest income	281	172	109	63 %
Interest expense	(19,296)	(15,434)	(3,862)	25 %
Income before income taxes	64,415	59,622	4,793	8 %
Income tax provision	(2,689)	(2,915)	226	(8)%
Net income	$61,726	$56,707	$5,019	9 %

* not meaningful

Analysis of Consolidated Operating Results

Net loss was $13.2 million and $7.8 million for the three months ended June 30, 2018 and 2017, respectively and operating (loss) income was $(4.2) million and $1.1 million for the three months ended June 30, 2018 and 2017, respectively. Operating results for the three months ended June 30, 2018 and 2017 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 $(4.7) million and $3.9 million, respectively. Excluding these unrealized items, operating income for the three months ended June 30, 2018 increased $3.2 million, or 116%, as compared to the three months ended June 30, 2017.

Net income was $61.7 million and $56.7 million for the six months ended June 30, 2018 and 2017, respectively and operating income was $83.4 million and $74.7 million for the six months ended June 30, 2018 and 2017, respectively. Operating results for the six months ended June 30, 2018 and 2017 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 $32.9 million and $36.2 million, respectively. Excluding these unrealized items, operating income for the six months ended June 30, 2018 increased $11.9 million, or 31%, as compared to the six months ended June 30, 2017.

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

Reconciliation to Adjusted Gross Margin, EBITDA and Adjusted EBITDA

The following table sets forth a reconciliation of our consolidated operating income (loss) to our total adjusted gross margin, a non-GAAP measure, for the periods presented and a reconciliation of our consolidated net income to EBITDA and Adjusted EBITDA, non-GAAP measures, for the periods presented. See above “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 report. The table below also presents information on weather conditions for the periods presented.

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Reconciliation of Operating Income to Adjusted Gross Margin:				
Operating (loss) income	$(4,238)	$1,093	$83,430	$74,701
Operating costs and expenses not allocated to operating segments:				
Operating expenses	22,281	16,901	45,490	33,733
Selling, general and administrative	18,562	19,624	46,426	45,913
Depreciation and amortization	8,378	6,950	16,803	12,882
Add: unrealized loss (gain) on inventory derivatives (1)	971	(4,539)	(22,590)	(29,047)
Add: unrealized loss (gain) on prepaid forward contract derivatives (2)	—	(267)	—	(240)
Add: unrealized loss (gain) on natural gas transportation contracts (3)	3,716	949	(10,352)	(6,865)
Total adjusted gross margin (4):	$49,670	$40,711	$159,207	$131,077
Adjusted Gross Margin by Segment:				
Refined products (5)	$28,671	$23,815	$85,006	$63,293
Natural gas	5,055	2,568	43,003	41,158
Materials handling	14,269	12,798	27,417	22,723
Other operations	1,675	1,530	3,781	3,903
Total adjusted gross margin	$49,670	$40,711	$159,207	$131,077
Reconciliation of Net Income to Adjusted EBITDA				
Net (loss) income	$(13,195)	$(7,792)	$61,726	$56,707
Add/(deduct):				
Interest expense, net	9,243	8,191	19,015	15,262
Tax provision	(286)	813	2,689	2,915
Depreciation and amortization	8,378	6,950	16,803	12,882
EBITDA (4):	$4,140	$8,162	$100,233	$87,766
Add: unrealized loss (gain) on inventory derivatives (1)	971	(4,539)	(22,590)	(29,047)
Add: unrealized (gain) loss on prepaid forward contract derivatives (2)	—	(267)	—	(240)
Add: unrealized loss (gain) on natural gas transportation contracts (3)	3,716	949	(10,352)	(6,865)
Biofuel tax credit (5)	—	—	(4,022)	—
Acquisition related expenses (6)	252	636	695	985
Other adjustments (7)	197	—	391	—
Adjusted EBITDA	$9,276	$4,941	$64,355	$52,599
Other Data:				
Ten Year Average Heating Degree Days (8)	575	583	3,232	3,268
Heating Degree Days (8)	666	608	3,242	3,073
Variance from average heating degree days	16%	4%	—%	(6)%
Variance from prior period heating degree days	10%	(7)%	5%	(6)%

Table of Contents

(1) Inventory is valued at the lower of cost or net realizable value. 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 contract derivatives 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 and changes in the fair value are therefore not included in net income (loss). 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 prepaid forward contract appreciates or declines, which creates unrealized hedging (gains) losses that are included in net income (loss).

(3) The unrealized loss (gain) 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) On February 9, 2018, the U.S. federal government enacted legislation that reinstated an excise tax credit program available for certain of our biofuel blending activities. The program had expired on December 31, 2016 and was reinstated retroactively to January 1, 2017. During the six months ended June 30, 2018, we recorded excise tax credits of $4.0 million that relate to blending activities that occurred during the year ended December 31, 2017, resulting in an increase in adjusted gross margin during the period.

(6) Beginning in the fourth quarter of 2017, we have excluded the impact of acquisition related expenses from our calculation of adjusted EBITDA. We incur expenses in connection with acquisitions and given the nature, variability of amounts, and the fact that these expenses would not have otherwise been incurred as part of our continuing operations, adjusted EBITDA excludes the impact of acquisition related expenses. Adjusted EBITDA for prior periods have been revised to conform to this presentation.

(7) Represents the change in the fair value of contingent consideration related to the 2017 Coen Energy acquisition and other expense.

(8) We use heating degree day amounts as reported by the NOAA Regional Climate Center. Prior to April 1, 2018, we reported degree day information utilizing the New England oil home heating region and for comparison purposes we used historical degree day information for the New England oil home heating region over the period of 1981-2011. Commencing April 1, 2018, we report degree day information for Boston and New York City (weighted equally) with a historical average for the same locations over the previous ten-year period. We made these changes to incorporate more recent average information and to better reflect the geographic locations of our customer base. All degree day amounts in this document have been revised to conform to this presentation.

Table of Contents

Analysis of Operating Segments
Three Months Ended June 30, 2018 compared to Three Months Ended June 30, 2017

	Three Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	304,248	270,312	33,936	13 %
Natural gas (MMBtus)	12,325	13,510	(1,185)	(9)%
Materials handling (short tons)	577	695	(118)	(17)%
Materials handling (gallons)	127,638	152,418	(24,780)	(16)%
Net Sales:				
Refined products	$ 664,025	$ 430,984	$ 233,041	54 %
Natural gas	58,428	65,708	(7,280)	(11)%
Materials handling	14,218	12,798	1,420	11 %
Other operations	4,985	4,136	849	21 %
Total net sales	$ 741,656	$ 513,626	$ 228,030	44 %
Adjusted Gross Margin:				
Refined products	$ 28,671	$ 23,815	$ 4,856	20 %
Natural gas	5,055	2,568	2,487	97 %
Materials handling	14,269	12,798	1,471	11 %
Other operations	1,675	1,530	145	9 %
Total adjusted gross margin	$ 49,670	$ 40,711	$ 8,959	22 %
Adjusted Unit Gross Margin:				
Refined products	$ 0.094	$ 0.088	$ 0.006	7 %
Natural gas	$ 0.410	$ 0.190	$ 0.220	116 %

Refined Products
Refined products net sales increased $233.0 million, or 54%, compared to the same period last year, due to a combination of higher prices and volumes. The 37% increase in sales prices reflects the higher refined products price environment compared to the same period last year. The 13% increase in volume was driven primarily by higher distillate sales due to a combination of the incremental volumes from the Coen Energy acquisition completed in October 2017 and gains at our other locations. Gasoline and heavy oil volumes were also modestly higher, although these increases were largely offset by a reduction in asphalt due to Kildair’s shift from marketing of asphalt to materials handling in March 2018.
Refined products adjusted gross margin increased $4.9 million, or 20%, compared to the same period last year. The increase in adjusted gross margin was primarily a result of the contribution from the Coen Energy acquisition, which was partially offset by a reduction at Kildair due to a combination of lower heavy fuel oil barge sale opportunities and the shift of asphalt margin from refined products to materials handling. Refined Products adjusted gross margin excluding Coen Energy and Kildair increased modestly, driven by higher volumes during the colder weather in the early part of the second quarter compared to last year, with heating degree days 10% higher compared to the same period last year.
Natural Gas
Natural gas net sales declined $7.3 million, or 11%, compared to the same period last year as a result of a 9% decrease in volumes. The key factors leading to the lower volumes was the loss of some higher volume accounts as well as higher competitive intensity in some markets.

Natural gas adjusted gross margin increased $2.5 million, or 97%, compared to the same period last year, as a result of substantially higher adjusted unit gross margins. The increase in adjusted unit gross margins was primarily driven by a stronger valuation of forward positions due to more favorable natural gas and credit market conditions.

Table of Contents

Materials Handling

Materials handling net sales and adjusted gross margin both increased approximately $1.4 million, or 11%, compared to the same period last year. Incremental asphalt revenue at Kildair was the primary factor due to the new asphalt materials handling agreement that began in March 2018. This agreement has transitioned the bulk of the asphalt margin previously recognized by Kildair as refined products into the materials handling segment. Other materials handling activities were comparable to last year, as gains from further break bulk business, in particular heavy lift revenue, were offset by reduced liquid bulk revenue due substantially to timing of asphalt activity.

Other Operations

Net sales from other operations increased $0.8 million, or 21%, as a result of the higher coal price environment compared to the same period last year. Adjusted gross margin increased $0.1 million.

Six Months Ended June 30, 2018 compared to Six Months Ended June 30, 2017

	Six Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	880,488	743,022	137,466	19 %
Natural gas (MMBtus)	32,582	33,714	(1,132)	(3)%
Materials handling (short tons)	1,370	1,276	94	7 %
Materials handling (gallons)	197,610	227,682	(30,072)	(13)%
Net Sales:				
Refined products	$ 1,844,885	$ 1,212,574	$ 632,311	52 %
Natural gas	188,355	185,374	2,981	2 %
Materials handling	27,366	22,723	4,643	20 %
Other operations	12,198	10,762	1,436	13 %
Total net sales	$ 2,072,804	$ 1,431,433	$ 641,371	45 %
Adjusted Gross Margin:				
Refined products	$ 85,006	$ 63,293	$ 21,713	34 %
Natural gas	43,003	41,158	1,845	4 %
Materials handling	27,417	22,723	4,694	21 %
Other operations	3,781	3,903	(122)	(3)%
Total adjusted gross margin	$ 159,207	$ 131,077	$ 28,130	21 %
Adjusted Unit Gross Margin:				
Refined products	$ 0.097	$ 0.085	$ 0.012	14 %
Natural gas	$ 1.320	$ 1.221	$ 0.099	8 %

Refined Products

Refined products net sales increased $632.3 million, or 52%, compared to the same period last year, due to a combination of higher prices and volumes. The 28% higher sales prices reflect the substantial increase in the refined products price environment compared to the same period last year. The 19% increase in volume was driven principally by distillates, including the contribution from the Coen Energy acquisition completed in October 2017 and the April 2017 Carbo acquisition. Distillate volumes were also higher for discretionary sales, in particular early in the year when a period of severe weather conditions led to competitor supply outages. In addition, heavy oil sales were higher than last year at both Sprague Resources and Kildair, with the colder weather a contributing factor. Reflecting the colder weather, the cumulative heating degree days were 5% higher compared to the same period last year.

Refined products adjusted gross margin increased $21.7 million, or 34%, compared to the same period last year. This gain was due to a combination of a 19% increase in volume as well as a 14% increase in adjusted unit gross margin. Key factors contributing to the higher adjusted unit gross margins included the aforementioned competitor supply outages as well as the retroactive reinstatement of the excise tax credit program on February 9, 2018. This program applies to certain of our biofuel blending activities and the reinstatement led to us recording an excise tax credit of $4.0 million during the six months ended June, 2018 related to 2017 blending activities. These margin gains more than offset the less attractive market conditions to store inventory.

Natural Gas

Natural gas net sales increased $3.0 million, or 2%, compared to the same period last year as a result of the higher natural gas price environment. Sales volumes were 3% lower than the same period last year largely due to the loss of some higher volume accounts as well as higher competitive intensity in some markets. This decline in volume was partially offset by the inclusion of six months of volume associated with customers acquired via the Global acquisition as compared to a five month period last year.

Natural gas adjusted gross margin increased by $1.8 million, or 4%, compared to the same period last year, due to the 14% higher adjusted unit gross margins. The increase in adjusted unit gross margin was primarily a result of improved performance achieved during the severe weather conditions in the early part of 2018 as well as the loss of some higher volume lower unit margin accounts.

Materials Handling

Materials handling net sales and adjusted gross margin both increased $4.6 million, or approximately 21%, compared to the same period last year. Incremental revenue at Kildair was the primary factor due to the new asphalt materials handling agreement that began in March 2018. Materials handling margin also benefited from new contracts at two other Sprague terminals, increased heavy lift activity, and timing differences of dry bulk materials.

Other Operations

Net sales from other operations increased by $1.4 million, or 13%, as a result of the higher coal price environment compared to the same period last year. Adjusted gross margin was $0.1 million lower.

Operating Costs and Expenses

Three Months Ended June 30, 2018 compared to Three Months Ended June 30, 2017

	Three Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands)			
Operating expenses	$22,281	$16,901	$ 5,380	32%
Selling, general and administrative	$18,562	$19,624	$ (1,062)	(5)%
Depreciation and amortization	$8,378	$6,950	$ 1,428	21%
Interest expense, net	$9,243	$8,191	$ 1,052	13%

Operating Expenses. Operating expenses increased $5.4 million, or 32%, compared to the same period last year, reflecting $4.5 million of operating expenses related to the Coen Energy acquisition and $0.9 million of higher employee related and other operating expenses predominately attributable to activity at our terminals.

Selling, General and Administrative Expenses. SG&A expenses decreased $1.1 million, or 5%, compared to the same period last year. This decline was driven by a decrease in unit-based compensation of $1.7 million due to a decrease in the estimated number of units that are expected to vest over the vesting period and lower acquisition related expenses of $0.4 million partially offset by an increase of $1.1 million connected to our Coen Energy acquisition.

Depreciation and Amortization. Depreciation and amortization increased $1.4 million, or 21%, compared to the same period last year, primarily as a result of the Coen acquisition.

35

Table of Contents

Interest Expense, net. Interest expense, net increased $1.1 million, or 13%, compared to the same period last year primarily relating to increased working capital requirements due to higher commodity prices and higher inventory and accounts receivables, and rising interest rates resulting from increases in financial rates and a step-up into a higher pricing tier within the acquisition facility of our Credit Agreement.

Six Months Ended June 30, 2018 compared to Six Months Ended June 30, 2017

	Six Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
	(in thousands)			
Operating expenses	$45,490	$33,733	$ 11,757	35%
Selling, general and administrative	$46,426	$45,913	$ 513	1%
Depreciation and amortization	$16,803	$12,882	$ 3,921	30%
Interest expense, net	$19,015	$15,262	$ 3,753	25%

Operating Expenses. Operating expenses increased $11.8 million, or 35%, compared to the same period last year, reflecting $9.4 million of operating expenses related to the 2017 acquisitions and $2.1 million of increased employee related, boiler fuel, insurance, legal and utility expenses predominantly attributable to activity at our terminals.

Selling, General and Administrative Expenses. SG&A expenses increased $0.5 million or 1%, compared to the same period last year. This increase was driven by expenses of $2.1 million connected to our Coen Energy acquisition offset by $1.7 million of decreased unit-based compensation due to a decrease in the estimated number of units that are expected to vest over the vesting period and lower acquisition related costs.

Depreciation and Amortization. Depreciation and amortization increased $3.9 million, or 30%, compared to the same period last year, primarily as a result of acquisitions during 2017.

Interest Expense, net. Interest expense, net increased $3.8 million, or 25%, compared to the same period last year primarily relating to increased working capital requirements due to higher commodity prices and higher inventory and accounts receivables, and rising interest rates resulting from increases in financial rates and a step-up into a higher pricing tier within the acquisition facility of our Credit Agreement.

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 June 30, 2018, we had working capital of $189.0 million.

As of June 30, 2018, the undrawn borrowing capacity under the working capital facilities of our Credit Agreement was $132.5 million and the undrawn borrowing capacity under the acquisition facility was $170.9 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 six months ended June 30, 2018, the amount drawn under the working capital facilities of our Credit Agreement fluctuated from a low of $178.6 million to a high of $395.6 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.

36

Table of Contents

Credit Agreement

Sprague Operating Resources LLC and Kildair are borrowers under an amended and restated revolving credit agreement (our "Credit Agreement") that matures on April 27, 2021. Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

As of June 30, 2018, the revolving credit facilities under the Credit Agreement contained, among other items, the following:

- A U.S. dollar revolving working capital facility of up to $950.0 million, subject to borrowing base limits, to be used for working capital loans and letters of credit;
- A multicurrency revolving working capital facility of up to $100.0 million, subject to borrowing base limits, to be used for working capital loans and letters of credit;
- A revolving acquisition facility of up to $550.0 million, subject to the acquisition facility borrowing base limits, 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 including the receipt of additional commitments from lenders, the ability to increase the U.S. dollar revolving working capital facility by $250.0 million and the multicurrency revolving working capital facility by $220.0 million, subject to a maximum increase for both facilities of $270.0 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 bears interest, at the borrowers' option, at a rate per annum equal to either (i) 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 (ii) an alternate rate plus a specified margin.

For loans denominated in U.S. dollars, the alternate rate is the Base Rate which is the highest of (a) the U.S. Prime Rate as in effect from time to time, (b) the greater of the Federal Funds Effective Rate and the Overnight Bank Funding 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 loans denominated in Canadian dollars, 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 1.25% to 2.25% for loans bearing interest at the alternate Base Rate and from 2.25% 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. Overdue amounts bear interest at the applicable rates described above plus an additional margin of 2%.

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, but not limited to, covenants that require the Partnership 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 and a maximum consolidated senior secured leverage-to-EBITDA ratio. The credit agreement also limits the Partnership's 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 June 30, 2018.

37

Table of Contents

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-acceleration, 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. We define maintenance capital expenditures as 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. We define expansion capital expenditures as 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 business combinations:

	Capital Expenditures		
	Expansion	Maintenance	Total
	(in thousands)		
Six Months Ended June 30,			
2018	$4,032	$ 5,266	$9,298
2017	$15,334	$ 3,784	$19,118

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

Cash Flows

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Net cash provided by operating activities	$205,332	$223,360
Net cash used in investing activities	$(9,255)	$(90,437)
Net cash used in financing activities	$(194,261)	$(132,015)

Operating Activities

Net cash provided by operating activities for the six months ended June 30, 2018 was $205.3 million and was primarily driven by cash inflows as a result of a decrease of $156.5 million in inventories due to a seasonal reduction in inventory requirements, a decrease of $131.4 million in accounts receivable due to a seasonal reduction in sales volume, and $61.7 million in net income. These inflows were offset by cash outflows as a result of a reduction of $130.3 million in accounts payable and accrued liabilities primarily relating to the timing of invoice payments for product purchases and $59.5 million representing the net impact in our derivative instruments as a result of changes in commodity prices during the period and seasonal reduction.

Table of Contents

Net cash provided by operating activities for the six months ended June 30, 2017 was $223.4 million and was primarily driven by cash inflows as a result of a decrease of $163.9 million in inventories due to a seasonal reduction in inventory requirements, a decrease of $102.7 million in accounts receivable due to a seasonal reduction in sales volume, and $56.7 million in net income. These inflows were offset by cash outflows as a result of a reduction of $91.5 million in accounts payable and accrued liabilities primarily relating to the timing of invoice payments for product purchases and an increase of $41.2 million in our derivative instruments as a result of changes in commodity prices during the period.

Investing Activities

Net cash used in investing activities for the six months ended June 30, 2018 was $9.3 million of which $4.0 million related to expansion capital expenditures and $5.3 million related to maintenance capital expenditure projects across our terminal system.

Net cash used in investing activities for the six months ended June 30, 2017 was $90.4 million of which $72.2 million related to the purchase of four acquisitions. There were additional investing activities of $15.3 million related to expansion capital expenditures and $3.8 million related to maintenance capital expenditure projects across our terminal system.

Financing Activities

Net cash used in financing activities for the six months ended June 30, 2018 was $194.3 million, and primarily resulted from $155.5 million of payments under our Credit Agreement due to reduced financing requirements from accounts receivable levels and the reduction of seasonal inventory levels and distributions of $34.2 million.

Net cash used in financing activities for the six months ended June 30, 2017 was $132.0 million, and primarily resulted from $97.9 million of net payments under our Credit Agreement due to reduced financing requirements from lower commodity prices and accounts receivable levels and distributions of $27.9 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 six months ended June 30, 2018 and 2017.

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 Condensed Consolidated Financial Statements are detailed in Note 1 “Description of Business and Summary of Significant Accounting Policies” included in our 2017 Annual Report and as updated in Note 2 to this Quarterly Report as it relates to revenue recognition. There have been no 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.

Recent Accounting Pronouncements

For information on recent accounting pronouncements impacting our business, see "Recent Accounting Pronouncements" included under Note 1 to our Condensed Consolidated Financial Statements.

Table of Contents

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 the 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. 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 ("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 June 30,		Six Months Ended June 30,	
	(in thousands)			
	2018	2017	2018	2017
Refined products contracts	$(1,227)	$11,351	$8,976	$44,918
Natural gas contracts	(3,832)	(406)	(2,960)	14,758
Total	$(5,059)	$10,945	$6,016	$59,676

Substantially all of our commodity derivative contracts outstanding as of June 30, 2018 will settle prior to December 31, 2019.

Table of Contents

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 June 30, 2018 were as follows (in thousands):

Beginning	Ending	Notional Amount
January 2018	January 2019	$275,000
January 2019	January 2020	$300,000
January 2020	January 2021	$300,000
January 2021	January 2022	$300,000
January 2022	January 2023	$250,000

During the two year period ended June 30, 2018 we hedged approximately 45% 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 June 30, 2018, we estimate that if short-term interest rates increased or decreased 100 basis points, our interest expense would have increased approximately $3.7 million and decreased approximately $3.7 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 our derivative assets and derivative liabilities measured at fair value on a recurring basis as of June 30, 2018:

	As of June 30, 2018			
	Fair Value Measurement	Active Markets Level 1	Observable Inputs Level 2	Unobservable Inputs Level 3
	(in thousands)			
Derivative assets:				
Commodity fixed forwards	$18,426	$—	$ 18,426	$ —
Commodity swaps and options	36,616	36,612	4	—
Commodity derivatives	55,042	36,612	18,430	—
Interest rate swaps	5,311	—	5,311	—
Total derivative assets	$60,353	$36,612	$ 23,741	$ —
Derivative liabilities:				
Commodity exchange contracts	$7	$7	$ —	$ —
Commodity fixed forwards	22,692	—	22,692	—
Commodity swaps and options	25,658	25,641	17	—
Commodity derivatives	48,357	25,648	22,709	—
Interest rate swaps	250	—	250	—
Other	52	—	52	—
Total derivative liabilities	$48,659	$25,648	$ 23,011	$ —

Table of Contents

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.

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 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 at times may exceed federally insured limits. We have not experienced any losses on such accounts.

Table of Contents

Item 4. Controls and Procedures

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to ensure that information required to be disclosed in the Partnership's reports filed or submitted 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 in the Partnership's reports under the Exchange Act is accumulated and communicated to the Partnership's management, including its President and Chief Executive Officer and Senior Vice President, Chief Operating Officer and Chief Financial Officer of our General Partner, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2018, the Partnership carried out an evaluation, under the supervision and with the participation of management (including the President and Chief Executive Officer and the Senior Vice President, Chief Operating Officer and Chief Financial Officer of the General Partner) of the effectiveness of the design and operation of the Partnership's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based on this evaluation, the General Partner's President and Chief Executive Officer and Senior Vice President, Chief Operating Officer and Chief Financial Officer concluded that the Partnership's disclosure controls and procedures were effective as of June 30, 2018.

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 June 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Partnership’s internal control over financial reporting.

Table of Contents

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 Part I, Item 1A "Risk Factors" included in our 2017 Annual Report, which could materially affect our business, financial condition or future results.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

The exhibits listed in the accompanying Exhibits Index are filed or incorporated by reference as part of this Form 10-Q.

EXHIBIT INDEX

Exhibit No.	Description
2.1***	Purchase and Sale Agreement, dated September 18, 2017, by and among Sprague Operating Resources LLC, Coen Oil Company, LLC, Coen Markets, Inc., and The Thomaston Land Company, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed September 19, 2017 (File No. 001-36137)).
2.2***	First Amendment dated April 18, 2017 to Asset Purchase Agreement by and among Sprague Operating Resources LLC, Carbo Industries, Inc. and Carbo Realty, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP’s Current Report on Form 8-K filed April 19, 2017 (File No. 001-36137)).
2.3***	Asset Purchase Agreement, dated March 13, 2017, by and among Carbo Industries, Inc., Carbo Realty, LLC, and Paul Hochhauser and Sprague Operating Resources, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP’s Current Report on Form 8-K filed March 16, 2017 (File No. 001-36137)).
2.4***	Asset Purchase Agreement, dated January 24, 2017, by and among Capital Properties, Inc., Dunellen, LLC, Capital Terminal Company and Sprague Operating Resources LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP’s Current Report on Form 8-K filed January 25, 2017 (File No. 001-36137)).
2.5***	Terminal and Wholesale Fuels Asset Purchase Agreement, dated January 23, 2017, by and between Leonard E. Belcher Incorporated and Sprague Operating Resources LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP’s Current Report on Form 8-K filed January 23, 2017 (File No. 001-36137)).
2.6***	Asset Purchase Agreement, dated December 30, 2016, by and among Sprague Operating Resources LLC, Sprague Energy Inc., Sprague Resources LP, Global Montello Group Corp., Global Energy Marketing LLC and Global Partners LP (incorporated by reference to Exhibit 2.1 of Sprague Resources LP’s Current Report on Form 8-K filed January 3, 2017 (File No. 001-36137)).
3.1	Certificate of Limited Partnership of Sprague Energy Partners LP (incorporated by reference to Exhibit 3.1 of Sprague Resources LP’s Registration Statement on Form S-1 filed July 27, 2011 (File No. 333-175826)).
3.2	Amendment to the Certificate of Limited Partnership of Sprague Energy Partners LP (Changing Name to Sprague Resources LP) (incorporated by reference to Exhibit 3.2 of Sprague Resources LP’s Registration Statement on Form S-1 filed July 27, 2011 (File No. 333-175826)).
3.3	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Sprague Resources LP dated as of October 30, 2013 effective December 20, 2017 (incorporated by reference to Exhibit 3.1 of Sprague Resources LP's Current Report on Form 8-K filed December 20, 2017 (File No. 001-36137)).
3.4	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)).

3.5	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)).
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.

Table of Contents

EXHIBIT INDEX (Continued)

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.
***	Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules to the Asset Purchase Agreements have been omitted. The registrant hereby agrees to furnish supplementally to the SEC, upon its request, any or all omitted schedules.

Table of Contents

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: August 8, 2018	/s/ Gary A. Rinaldi
	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)