Sprague Resources LP
Form 10-K
March 16, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2014

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission File Number: 001-36137

Sprague Resources LP

(Exact name of registrant as specified in its charter)

Delaware	**45-2637964**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

185 International Drive

Portsmouth, New Hampshire 03801

(Address of principal executive offices, including zip code)

Registrant s telephone number, including area code: (800) 225-1560

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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 ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant was $216,050,924 as of June 30, 2014 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such units as quoted on the New York Stock Exchange. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The registrant had 10,995,377 common units and 10,071,970 subordinated units outstanding as of March 9, 2015.

Documents Incorporated by Reference: None

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SPRAGUE RESOURCES LP

ANNUAL REPORT ON FORM 10-K

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PART I

Item 1. Business

As used in this Annual Report on Form 10-K (Annual Report), unless the context otherwise requires, references to Sprague Resources, the Partnership, we, our, us, or like terms, when used in a historical context prior to October 30, 2013, the date on which we completed an initial public offering of common units representing limited partner interests in Sprague Resources LP, refer to Sprague Operating Resources LLC, our Predecessor for accounting purposes and the successor to Sprague Energy Corp., also referenced as our Predecessor or the Predecessor and when used in the present tense or prospectively, refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to Axel Johnson or the Parent refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its general partner. References to Sprague Holdings refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of our general partner. References to our general partner refer to Sprague Resources GP LLC.

Our Partnership

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our general partner to engage in the storage, distribution and sale of refined petroleum, what we refer to as refined products, and natural gas, and we also provide storage and handling services for a broad range of materials.

In October 2013, we completed an initial public offering of common units representing limited partner interests in the Partnership (the IPO). Our common units now trade on the New York Stock Exchange (the NYSE).

We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own, operate and/or control a network of 19 refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of approximately 14.1 million barrels for refined products and other liquid materials, as well as approximately 1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 2.3 million barrels of additional storage capacity attributable to 47 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to approximately 60 third-party terminals in the Northeast United States through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

Our principal executive offices are located at 185 International Drive, Portsmouth, New Hampshire 03801. Our telephone number is (800) 225-1560. Our internet address is *http://www.spragueenergy.com*. We make available through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission, or the SEC. The SEC maintains an internet site at *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

We operate under four business segments: refined products, natural gas, materials handling and other operations. Our refined products segment purchases a variety of refined products, such as heating oil, diesel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (primarily from refining companies, trading organizations and producers), and sells 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 we sell to them. Our wholesale customers consist of more than 1,100 home heating oil retailers and diesel fuel and gasoline

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resellers. Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, hospitals, educational institutions and asphalt paving companies. For the years ended December 31, 2014, 2013 and 2012, we sold approximately 1.7 billion, 1.5 billion and 1.3 billion gallons of refined products, respectively. For the years ended December 31, 2014, 2013 and 2012, our refined products segment accounted for 60%, 61% and 56% of our adjusted gross margin, respectively. See Segment Reporting included under Note 17 to our Consolidated and Combined Financial Statements for a presentation of financial results by reportable segment and see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operation for a discussion of financial results by segment.

Our natural gas segment purchases, sells and distributes natural gas to more than 15,000 commercial and industrial customer locations across 13 states in the Northeast and Mid-Atlantic United States. We purchase the natural gas we sell from natural gas producers and trading companies. For the years ended December 31, 2014, 2013 and 2012, we sold 54.4 Bcf, 52.0 Bcf and 49.4 Bcf of natural gas, respectively. For the years ended December 31, 2014, 2013 and 2012, our natural gas segment accounted for 23%, 21% and 19% of our adjusted gross margin, respectively.

Our materials handling business is a fee-based business and is generally conducted under multi-year agreements. We offload, store and/or prepare for delivery a variety of customer owned products, including asphalt, crude oil, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. For the year ended December 31, 2014, we offloaded, stored and/or prepared for delivery, 2.7 million short tons of product and 309.8 million gallons of liquid materials. For the years ended December 31, 2013 and 2012 we offloaded, stored and/or prepared for delivery 2.1 million and 2.6 million short tons of products, and 246.7 million and 248.5 million gallons of liquid materials, respectively. For the years ended December 31, 2014, 2013 and 2012, our materials handling segment accounted for 15%, 15% and 23% of our adjusted gross margin, respectively.

Our other operations consist primarily of coal marketing and distribution and commercial trucking, and for the years ended December 31, 2014, 2013 and 2012, such activities accounted for 2%, 3% and 2% of our adjusted gross margin, respectively.

We take title to the products we sell in our refined products and natural gas segments. We do not take title to any of the products in our materials handling segment. 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.

Acquisitions

In December 2014, we completed the acquisition of all of the equity interests in Kildair Service Ltd. (Kildair) through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties LLC, for total consideration of $175.0 million, which included $10.0 million in unregistered common units of Sprague Resources LP. Kildair owns a terminal in Sorel-Tracy, Quebec, on the St. Lawrence River where it maintains 3.3 million barrels of residual fuel, asphalt, and crude oil storage. Kildair s primary businesses include marketing of residual fuel both locally and for export, marketing of asphalt including polymer modified grades, and crude-by-rail handling services. Kildair s terminal has blending infrastructure allowing the ability to process a wide range of varying quality blend components. The facility also includes an asphalt and residual fuel oil testing laboratory, 25 truck and railcar loading and offloading racks, 120 railcars of offload capacity, including 60 in the new crude oil rail offloading section, and a dock with the capability to load or receive ships with up to 450,000 barrels of capacity.

Our Predecessor owned a 50% equity interest in Kildair during the period from October 2007 through October 1, 2012 and had completed the purchase of the remaining 50% equity interest on October 1, 2012.

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Kildair was not included in the Partnership s Consolidated and Combined Financial Statements effective October 30, 2013, the IPO date, at which time Kildair was distributed to an affiliate of the Parent. As the acquisition of Kildair by the Partnership represents a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast to include the historical results of Kildair for all periods presented when Kildair was controlled by Axel Johnson.

In December 2014, we acquired substantially all of the assets of Castle Oil (Castle), including Castle s Bronx terminal and its associated wholesale, commercial and retail fuel distribution business for $45.3 million in cash, an obligation to pay $5.0 million over a three year period (net present value of $4.6 million) and approximately $5.3 million in unregistered common units, plus payments for inventory and other current assets of approximately $37.0 million. Castle s Bronx terminal is a large deepwater petroleum products terminal located in New York City, with a total storage capacity of 907,000 barrels, handling distillates, residual fuel, asphalt and biodiesel.

On October 1, 2014, the Partnership purchased Metromedia Gas & Power Inc. s (Metromedia Energy) natural gas marketing and electricity brokerage business for $22.0 million, not including the purchase of natural gas inventory, utility security deposits, and other adjustments. Total consideration at closing was $32.8 million. Metromedia Energy markets natural gas and brokers electricity to commercial, industrial and municipal consumers in the Northeast and Mid-Atlantic United States. The acquisition was accounted for as a business combination and was financed with borrowings under the Partnership s credit facility.

In July, 2013, our Predecessor purchased an oil terminal in Bridgeport, Connecticut for $20.7 million. This deep water facility includes 13 storage tanks with 1.3 million barrels of storage capacity for gasoline and distillate products with 11 storage tanks and 1.1 million barrels currently in service. The terminal provides throughput services to third-parties for branded gasoline sales in the Connecticut market.

Business Strategies

Our plan is to generate cash flows sufficient to enable us to maintain the current levels of quarterly distribution on each unit and to increase distributable cash flow per unit by executing the following strategies:

- ***Acquire additional terminals and marketing and distribution businesses that are accretive***. We intend to grow our asset and customer base by acquiring additional marine and inland terminals (both refined products and materials handling) within and adjacent to the geographic markets we currently serve. We also intend to acquire additional refined products and natural gas marketing businesses that have demonstrated an ability to generate free cash flow and that will enable us to leverage our existing investment in our business and customer service systems to further increase profitability and stability of such cash flow.

- ***Increase our business with existing customers.*** We intend to increase the net sales and margin we realize from customers we currently serve by expanding the range of products and services we provide and by developing additional ways to address our customers needs for certainty of supply, reduced commodity price risk and high-quality customer service. Our goal is to be alert to our customers needs and be faster and more efficient than our competitors in responding to them.

Limit our exposure to commodity price volatility and credit risk. We take title to the products we sell in our refined products and natural gas segments, while our materials handling business is operated predominantly under fixed-fee, multi-year contracts. We will continue to manage our exposure to commodity prices by seeking to maintain a balanced position in our purchases and sales through the use of derivatives and forward contracts. In addition to managing commodity price volatility, we will continue to manage our counterparty risk by maintaining conservative credit management processes.

Maintain our operational excellence. We intend to maintain our long history of safe, cost-effective operations and environmental stewardship by applying new technologies, investing in the maintenance of our assets and providing training programs for our personnel. We have a Health, Safety and Environmental department primarily devoted to safety matters and reducing operational and

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environmental risks. We will work diligently to meet or exceed applicable safety and environmental regulations and we will continue to enhance our safety monitoring function as our business grows and operating conditions change.

Refined Products

Overview

The products we sell in our refined products segment can be grouped into three categories: distillates, gasoline, residual fuel oil and asphalt. Of our total volume sold in our refined products segment in 2014, distillates accounted for approximately 67%, gasoline accounted for approximately 14% and residual fuel oil and asphalt accounted for approximately 19%.

Distillates. We sell four kinds of distillates: heating oil (both unbranded and HeatForce®, our proprietary premium heating oil product), diesel fuel (both unbranded and RoadForce ®, our proprietary premium diesel fuel), kerosene and jet fuel. In 2014, heating oil accounted for approximately 58%, diesel fuel accounted for approximately 39%, and other distillates accounted for approximately 3% of the total volume of distillates we sold. Distillate volumes accounted for 67%, 64%, and 70% of our total refined products sales for the years ended December 31, 2014, 2013 and 2012, respectively.

We have the capability at several of our facilities to blend biodiesel with distillates in order to sell bio heating oil and biodiesel. In 2014, biofuel accounted for approximately 6% of the distillate fuel volumes we sold.

Gasoline. We sell unbranded gasoline in qualities that comply with seasonal and geographical requirements. Gasoline volumes accounted for 14%, 15% and 24% of our total refined products sales for the years ended December 31, 2014, 2013 and 2012, respectively.

Residual Fuel Oil and Asphalt. We sell various sulfur grades of residual fuel oil, blended to meet customer requirements, in our market areas. Residual fuel oil and asphalt volumes accounted for approximately 19%, 21% and 6% of our total refined products sales for the years ended December 31, 2014, 2013 and 2012, respectively.

In 2014, our refined products segment accounted for approximately 92% of our total net sales and 60% of our adjusted gross margin, as defined on page 46.

Customers, Contracts and Pricing

We sell heating oil, diesel fuel, kerosene, unbranded gasoline, jet fuel, residual fuel oil and asphalt to wholesalers, retailers and commercial customers. The majority of these sales are made free on board, or FOB, at the bulk terminal or inland storage facility we own and/or operate or with which we have storage and throughput arrangements, which means the price of products sold includes the cost of delivering such product to that location and any further shipping expenses are borne by the purchaser.

In 2014, we sold heating oil, including HeatForce®, to approximately 1,000 wholesale distributors and retailers. These sales are made through Sprague RealTime® pricing platform, and under rack agreements based upon our posted price, contracts with index-based pricing provisions and fixed price forward contracts.

In 2014, we sold diesel fuel, including RoadForce® premium diesel fuel, to approximately 640 wholesalers and transportation fuel distributors.

In 2014, we sold unbranded gasoline at 22 third-party locations primarily to resellers.

We sell residual fuel oil to approximately 1,900 commercial and industrial accounts. Sales were made under rack agreements and contracts with index-based pricing provisions.

We also sell heating oil, diesel fuel, unbranded gasoline and residual fuel oil to public sector entities through competitive bidding processes as well as distillate and residual fuel oil by truck and barge to marine customers.

Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, and educational institutions. Most of these sales are made on a delivered basis, whereby we either deliver the product with our own trucks and barges or arrange with third-party haulers to make deliveries on our behalf.

Our sales contracts to commercial customers generally are for terms of one to five years. We currently have contracts with the U.S. government as well as with numerous states, municipalities, agencies and educational institutions.

For the year ended December 31, 2014, no customer represented more than 10% of net sales for our refined products segment.

Natural Gas

Overview

We sell natural gas and related delivery services to customers primarily located in the Northeast and Mid-Atlantic United States. We deliver natural gas to customers through utility interconnections of pipelines and manage interactions with utilities on behalf of our customers. We sell natural gas pursuant to fixed price, floating price and other structured pricing contracts. We utilize physical trading as well as financial and derivative trading both over the counter and through exchanges such as the Intercontinental Exchange Inc. (ICE) and NYMEX, in order to manage our natural gas commodity price risk.

In order to manage our supply commitments to our customers and provide operational flexibility and arbitrage opportunities, we enter into supply contracts, leases for pipeline transportation capacity, leases for storage space and other physical delivery services for various terms. We believe that entering into these types of arrangements provides us with potential opportunities to grow our existing customer relationships and to pursue additional relationships.

For the year ended December 31, 2014, our natural gas segment accounted for approximately 7% of our total net sales, and 23% of our adjusted gross margin as defined on page 46.

Customers

Our natural gas customers operate in the industrial and commercial sectors in the Northeast United States, with the highest concentration in New England and New York. We acquired HESCO in 2006 and Metromedia Energy Inc. in 2014 as part of our strategy to target smaller to mid-size commercial and industrial customers as a key growth area. This strategy has led to a significant increase in the number of customers served and adjusted unit gross margin, with sales volumes remaining relatively stable. Examples of customers include industrial users of varying sizes (e.g., pulp and paper, chemicals, pharmaceutical and metals plants) to various commercial customers (e.g., hospitals, universities, apartment buildings and retail stores). The industrial customers have a high concentration of process load to support their manufacturing requirements, with the largest uses by the commercial customers typically for heating, cooling, lighting, cooking and drying.

For the year ended December 31, 2014, no customer represented more than 10% of net sales for our natural gas segment.

Contracts/Pricing

We use various types of contracts for the sale and delivery of natural gas to our customers, with terms ranging from month-to-month to over two years. We provide a wide range of pricing options to our customers, including daily pricing and long-term fixed pricing. For example, we may offer a contract that permits the customer to lock in a basis or location differential relative to the Henry Hub delivery location and then fix the price at a later date based on the prevailing market pricing. There are various other alternatives such as capped pricing (essentially setting a maximum) or daily pricing based on a differential to a published market index. Due to the commodity price risk associated with uncertain customer usage patterns, we generally avoid transactions that require a single price for all volumes delivered, with the pricing of the non-contractual volumes based on prevailing market economics.

Materials Handling

Overview

Materials handling is the movement of raw materials and finished goods through our waterfront terminals. We utilize our terminal network to offload, store and/or prepare for delivery a large number of liquid products, bulk and break bulk materials and heavy lift services and provide other handling services to many of the same customers that we supply with refined products.

We are capable of providing numerous types of materials handling services, including ship handling, crane operations, pile building, warehouse operations, scaling and, in some cases, transportation to the final customer. In all cases, we play the role of a distribution agent for our customers. Because the products we handle are generally owned by our customers, we have virtually no working capital requirements, commercial risk or inventory risk. Our materials handling contracts are typically long-term and predominately fee-based.

For the year ended December 31, 2014, our materials handling segment accounted for approximately 1% of our total net sales and 15% of our adjusted gross margin.

Major Types of Materials Handling and Services

The type of materials handling and services we provide can be divided into three major categories:

Liquid. Liquid products are moved to terminals via various types of ocean going vessels and offloaded into terminal tanks via pipelines on the dock of the facility. Examples of liquid materials handled include crude oil, refined products, asphalt and clay slurry. Liquid handling activities include securing the vessel, attaching product lines from ship pipes to dock product lines, supervising discharge into tanks, measuring tank quantities, storing product, loading product into authorized trucks or railcars and transporting product to its final destination. In some cases the products need to remain heated in storage to be able to flow at ambient temperatures. Kildair s operations include a materials handling contract involving transloading and storage of crude oil.

Bulk. Bulk materials are normally some type of aggregate materials moved in large vessels configured with multiple holds that store products on ships in piles with no other type of packaging. Examples of bulk material include salt, petroleum coke, gypsum, cement and coal. These vessels are normally offloaded via cranes that either reside on the vessel or on the dock of the terminal. In a typical discharge the services performed include: securing the vessel to the dock, operating the vessel cranes, transferring products to trucks via large dock hoppers, transporting the materials to a holding pad, building materials up into large storage piles, covering the piles with protective tarps, storing the product, loading the product into trucks or railcars, scaling the loaded trucks and sometimes transporting the product to its final destination.

Break bulk. Break bulk materials are shipped in less than bulk quantities normally with some type of secondary packaging. Examples of break bulk materials include one ton sacks of raw materials, pallets of stones, bales of raw wood pulp and rolls of paper. Another subcategory of break bulk materials is large construction project cargo such as windmill components, often referred to as heavy lift. Break bulk handling activities include securing vessels, unloading or loading vessels either with cranes or specialty fork trucks, transferring products into warehouses or onto pads for storage, reloading products onto trucks or railcars and sometimes transporting products to their final destinations.

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Customers

Our materials handling operations can service multiple customer types during any single operation, including: the ocean shippers, multiple logistics firms, trucking firms and the materials supplier or consumer. The materials we handle normally fall into two major categories. The first category involves raw materials or finished goods shipped by water into local markets to support local production, manufacturing or construction firms. Examples of these products include asphalt for road construction, gypsum rock for drywall manufacturing, road salt for local road treatment, petroleum coke or utility fuels for energy demand and clay slurry for finished paper treatment. The second category of materials we handle are materials manufactured locally for export via vessel to other countries. These materials include hardwood, wood pulp for paper manufacture in Asia or Europe and tallow for biodiesel production in Europe.

For the year ended December 31, 2014, we had one customer who represented 12% of net sales for our materials handling segment, although no customer represented more than 1% of our total net sales.

Contracts/Pricing

The typical contract term for our materials handling services varies depending on the frequency and type of service. For bulk and liquid services, the commodity is normally a raw materials input for industrial production (wood pulp) or construction of roads (asphalt) or wallboard (gypsum rock). As such, the demand is more ratable and the customer is normally in need of guaranteed space within a terminal. These customers typically enter into term contracts that can range from one to 20 years depending on the relative importance of the material to their production and the amount of any capital infrastructure that we need to develop for such customers. As of December 31, 2014, the weighted-average life of our materials handling contracts was approximately eight years, with a weighted-average remaining life of approximately five years, each based on adjusted gross margin as defined on page 46, attributable to these contracts. Historically, our customers have paid for terminal improvements for specialty handling systems such as a clay slurry screening plant, while we will pay for more generic handling systems such as storage pads.

For container and break bulk services, it is typical for the user of that material to contract on an individual shipment basis. For example, a typical pulp merchant may choose to sell its pulp domestically or to users in Europe or Asia depending on the highest delivered value it can yield. As such, its choice of delivery mode and terminal will be driven by the location of its final customer. Therefore, we normally maintain a published rate for most generic services. Those rates are subject to change depending on market conditions.

Other Operations

Our other operations segment includes the marketing and distribution of coal that is conducted in our South Portland and Portland, Maine terminals and commercial trucking activity in Kildair s operations. For the year ended December 31, 2014, our other operations segment accounted for less than 1% of our total net sales and 2% of our adjusted gross margin.

Commodity Risk Management

Because we take title to the refined products and natural gas that we sell, we are exposed to commodity risk. Our materials handling business is a fee-based business and, accordingly, our operations in that business segment have only limited exposure to commodity risk. Commodity risk is the risk of market fluctuations in the price of commodities such as refined products and natural gas. We endeavor to limit unfavorable commodity price risk in connection with our daily operations. Generally, as we purchase and/or store refined products, we reduce commodity risk through hedging by selling futures contracts on regulated exchanges or using other derivatives, and then close out the related hedge as we sell the product for physical delivery to third parties. Products are generally purchased and sold at spot prices, fixed prices or indexed prices. While we seek to use these transactions to maintain a position that is substantially balanced between purchased volumes and sales volumes through regulated exchanges or derivatives, we may experience net unbalanced positions for short periods of time as a result of variances in daily sales and transportation and delivery schedules, as well as logistical issues associated with inclement weather conditions or infrastructure disruptions. Our general policy is to not hold refined products futures contracts or other derivative products and instruments for the sole purpose of speculating on price changes. While our policies are designed to limit market risk, some degree of exposure to unforeseen fluctuations in market conditions remains.

Our operating results are sensitive to a number of factors. Such factors include commodity location, grades of product, individual customer demand for grades or location of product, localized market price structures, availability of transportation facilities, daily delivery volumes that vary from expected quantities and timing and costs to deliver the commodity to the customer. The term basis risk is used to describe the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of that commodity at a different time or place, including, without limitation, transportation costs and timing differentials. We attempt to reduce our exposure to basis risk by grouping our purchase and sale activities by geographical region and commodity quality in order to stay balanced within such designated region.

With respect to the pricing of commodities, we enter into derivative positions to limit or hedge the impact of market fluctuations on our purchase and forward fixed price sales of refined products. Any hedge ineffectiveness is reflected in our results of operations.

With respect to refined products, we primarily use a combination of futures contracts, over-the-counter swaps and forward purchases and sales to hedge our price risk. For light oils (gasoline and distillates), we primarily utilize the actively traded futures contracts on the regulated NYMEX as the derivatives to hedge our positions. Heavy oils are typically hedged with fixed-for-floating price residual fuel oil swaps contracts, which are either balanced by offsetting positions or financially settled (meaning that these swaps do not include a delivery option).

With respect to natural gas, we generally use fixed-for-floating price swaps contracts that trade on the ICE for hedging. As an alternative, we may use NYMEX natural gas futures for such purposes. In addition, we use natural gas basis swaps to hedge our basis risk.

For both refined products and natural gas, if we trade in any derivatives that are not cleared on an exchange, we strive to enter into derivative agreements with counterparties that we believe have a strong credit profile and/or provide us with significant trade credit to limit counterparty risk and margin requirements.

We monitor policies, processes and procedures designed to prevent unauthorized trading and to maintain substantial balance between purchases and sales or future delivery obligations. We can provide no assurance, however, that these steps will detect and/or prevent all violations of such risk management policies, processes and procedures, particularly if deception or other intentional misconduct is involved.

Storage and Distribution Services

Marine terminals and inland storage facilities play a key role in the distribution of product to our customers. We own, operate and/or control a network of 19 refined products and materials handling terminals strategically located throughout the Northeast United States and Quebec, Canada that have a combined storage capacity of approximately 14.1 million barrels for refined products and other liquid materials, as well as approximately 1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 2.3 million barrels of additional storage capacity attributable to 47 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to approximately 60 third-party terminals in the Northeast United States through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

The marine terminals and inland storage facilities from which we distribute product are supplied by ship, barge, truck, pipeline or rail. The inland storage facilities, which we use exclusively to store distillates, are supplied with product delivered by truck from marine and other bulk terminals. Our customers receive product from our network of marine terminals and inland storage facilities via truck, barge, rail or pipeline.

Our marine terminals consist of multiple storage tanks and automated truck loading equipment. These automated systems monitor terminal access, volumetric allocations, credit control and carrier certification through the identification of customers. In addition, some of the marine and inland terminals at which we market are equipped with truck loading racks capable of providing automated blending and additive packages that meet our customers specific requirements. Many of our marine and inland terminals operate 24 hours per day.

Throughput arrangements allow storage of product at terminals owned by others. These arrangements permit our customers to load product at third-party terminals while we pay the owners of these terminals fees for services rendered in connection with the receipt, storage and handling of such product. Payments we make to the terminal owners may be fixed or based upon the volume of product that is delivered and sold at the terminal.

Exchange agreements allow our customers to take delivery of product at a terminal or facility that is not owned or leased by us. An exchange is a contractual agreement pursuant to which the parties exchange product at their respective terminals or facilities. For example, we (or our customers) receive product that is owned by the other party from such party s facility or terminal and we deliver the same volume of product to such party (or to such party s customers) out of one of the terminals in our terminal network. Generally, both parties to an exchange transaction pay a handling fee (similar to a throughput fee) and often one party also pays a location differential that covers any excess transportation costs incurred by the other party in supplying product to the location at which the first party receives product. Other differentials that may occur in exchanges (and result in additional payments) include product value differentials.

Our Terminals

We own, operate, and/or control a network of 19 refined products and material handling terminals located along the coast of the Northeast United States from New York to Maine and Quebec, Canada. Our facilities are equipped to provide terminalling, storage and distribution of both solid and liquid products to serve our refined products and materials handling businesses. Each facility has capabilities that are unique to the local markets served. A majority of facilities additionally have demonstrated flexibility in their ability to handle liquid, dry bulk and break bulk products at the same terminal and in most cases across the same dock. This capability has offered us valuable flexibility to fully utilize each asset to meet a variety of fuel demands and third-party cargo handling demands as customer requirements have changed over the years.

We operate or control ten terminals that are capable of handling both liquid petroleum products and providing third-party materials handling services. Five terminals exclusively handle liquid petroleum products and four terminals are dedicated exclusively to materials handling services. Total liquid storage capacity throughout our owned and/or operated terminals is approximately 14.1 million barrels (which excludes approximately 2.3 million barrels of storage capacity not currently in service). Inside warehouse capacity at our owned and/or operated terminals totals approximately 316,000 square feet with approximately 1.2 million square feet of outside laydown space available.

For a more detailed description of our terminals, please read Item 2. Properties.

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Competition

We encounter varying degrees of competition based on product type and geographic location in the marketing of our refined products. In our Northeast United States market, we compete in various product lines and for a range of customer types. The principal methods of competition in our refined products operations are pricing, service offerings to customers, credit support and certainty of supply. Our competitors include terminal companies, major integrated oil companies and their marketing affiliates and independent marketers of varying sizes, financial resources and experience. We believe that our being one of the largest independent wholesale distributors of refined products in the Northeast United States (based on aggregate terminal capacity), our ownership of various marine-based terminals and our reputation for reliability and strong customer service provide us with a competitive advantage in marketing refined products in the areas in which we operate.

Competitors of our natural gas sales operations generally include natural gas suppliers and distributors of varying sizes, financial resources and experience, including producers, pipeline companies, utilities and independent marketers. The principal methods of competition in our natural gas operations are in obtaining supply, pricing optionality for customers and effective support services, such as scheduling and risk management. We believe that our sizeable market presence and strong customer service and offerings provide us with a competitive advantage in marketing natural gas in the areas in which we operate.

In our materials handling operations, we primarily compete with public and private port operators. Although customer decisions are substantially based on location, additional points of competition include types of services provided and pricing. We believe that our ability to provide materials handling services at a number of our refined products terminals and our demonstrated ability to handle a wide range of products provides us a competitive advantage in competing for products-related handling services in the areas in which we operate.

Seasonality

Demand for natural gas and some refined products, specifically heating oil and residual fuel oil for space heating purposes, is generally higher during the period of November through March than during the period of April through October. Therefore, our results of operations for the first and fourth calendar quarters are generally better than for the second and third calendar quarters. For example, over the 36-month period ended December 31, 2014, we generated an average of approximately 71% of our total heating oil and residual fuel oil net sales during the months of November through March.

Employees

Our general partner employs over 580 full-time employees who support our operations and also employs some part-time hourly workers who are on call during peak periods. Approximately 46 of the full-time employees are covered by collective bargaining agreements and we are in negotiations with two unions at the Bronx, NY terminal as part of the Castle acquisition for contracts to cover another 21 employees. Our subsidiary Kildair has approximately 100 employees, 36 of which are covered by collective bargaining agreements.

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Item 1A. Risk Factors

Common units are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business.

If any of the following risks were actually to occur, our business, financial condition, results of operations and ability to pay distributions to our unitholders could be materially adversely affected. Additional risks and uncertainties not currently known to us or that we currently consider to be immaterial may also materially adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

Risks Related to Our Business

We may not have sufficient distributable cash flow following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.

In order to pay the minimum quarterly distribution of $0.4125 per unit per quarter, or $1.65 per unit on an annualized basis, we will require distributable cash flow of approximately $8.6 million per quarter, or approximately $34.5 million per year, based on the number of common and subordinated units currently outstanding. We may not have sufficient distributable cash flow each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- Competition from other companies that sell refined products, natural gas and/or renewable fuels in the Northeast United States;
- Competition from other companies in the materials handling business;
- Demand for refined products, natural gas and our materials handling services in the markets we serve;
- Absolute price levels, as well as the volatility of prices, of refined products and natural gas in both the spot and futures markets;
- Seasonal variation in temperatures, which affects demand for natural gas and refined products such as heating oil and residual fuel oil to the extent that it is used for space heating; and
- Prevailing economic conditions.

In addition, the actual amount of distributable cash flow that we distribute will depend on other factors such as:

- The level of maintenance capital expenditures we make;

The level of our operating and general and administrative expenses, including reimbursements to our general partner and certain of its affiliates for services provided to us;

Fluctuations or changes in tax rates, including Canadian income and withholding taxes

The restrictions contained in our credit agreement, including borrowing base limitations and limitations on distributions;

Our debt service requirements;

The cost of acquisitions we make, if any;

Fluctuations in our working capital needs;

Our ability to access capital markets and to borrow under our credit agreement to make distributions to our unitholders; and

The amount of cash reserves established by our general partner, if any.

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Our distributable cash flow depends primarily on our cash flow and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.

Our distributable cash flow depends primarily on our cash flow, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Our business is seasonal and generally our financial results are lower in the second and third quarters of the calendar year, which may result in our need to borrow money in order to make quarterly distributions to our unitholders during these quarters.

Demand for natural gas and some refined products, specifically home heating oil and residual fuel oil for space heating purposes, is generally higher during the period of November through March than during the period of April through October. Therefore, our results of operations for the first and fourth calendar quarters are generally better than for the second and third calendar quarters. For example, over the 36-month period ended December 31, 2014, we generated an average of approximately 71% of our total heating oil and residual fuel oil net sales during the months of November through March in the Northeast United States. With reduced cash flow during the second and third calendar quarters, we may be required to borrow money in order to pay the minimum quarterly distribution to our unitholders. Any restrictions on our ability to borrow money could restrict our ability to make quarterly distributions to our unitholders.

A significant decrease in demand for refined products, natural gas or our materials handling services in the areas we serve would adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

A significant decrease in demand for refined products, natural gas or our materials handling services in the areas that we serve would significantly reduce our net sales and, therefore, adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. Factors that could lead to a decrease in market demand for refined products or natural gas include:

- Recession or other adverse economic conditions;
- Seasonal variation in temperature, which affects demand for natural gas and refined products, such as heating oil and residual fuel oil to the extent that it is used for space heating;
- High prices caused by an increase in the market price of refined products, higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products or natural gas;
- Increased conservation, technological advances and the availability of alternative energy, whether as a result of industry changes, governmental or regulatory actions or otherwise; and
- Conversion from consumption of heating oil or residual fuel oil to natural gas.

Factors that could lead to a decrease in demand for our materials handling services include weakness in the housing and construction industries and the economy generally.

Certain of our operating costs and expenses are fixed and do not vary with the volumes we store, distribute and sell. These costs and expenses may not decrease ratably, or at all, should we experience a reduction in our volumes stored, distributed and sold. As a result, we may experience declines in our operating margin if our volumes decrease.

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Our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders are influenced by changes in demand for, and therefore indirectly by changes in the prices of, refined products and natural gas, which could adversely affect our profit margins, our customers and suppliers financial condition, contract performance, trade credit and the amount and cost of our borrowing under our credit agreement.

Financial and operating results from our purchasing, storing, terminalling and selling operations are influenced by price volatility in the markets for refined products and natural gas. When prices for refined products and natural gas rise, some of our customers may have insufficient credit to purchase supply from us at their historical purchase volumes, and their customers, in turn, may adopt conservation measures which reduce consumption, thereby reducing demand for product. Furthermore, when prices increase rapidly and dramatically, we may be unable to promptly pass our additional costs to our customers, resulting in lower margins for a period of time before margins expand to cover the incremental costs. Significant increases in the costs of refined products can materially increase our costs to carry inventory. We use the working capital facility in our credit agreement, which limits the amounts that we can borrow, as our primary source of financing our working capital requirements. Lastly, higher prices for refined products or natural gas may (1) diminish our access to trade credit support or cause it to become more expensive and (2) decrease the amount of borrowings available for working capital as a result of total available commitments, borrowing base limitations and advance rates thereunder.

In addition, when prices for refined products or natural gas decline, the likelihood of nonperformance by our customers on forward contracts may be increased as they and/or their customers may attempt to not honor their contracts and instead purchase refined products or natural gas at the then lower spot or retail market price.

Restrictions in our credit agreement could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders as well as the value of our common units.

We will be dependent upon the earnings and cash flow generated by our operations in order to meet our debt service obligations and to allow us to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our credit agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business, which may, in turn, adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. For example, our credit agreement restricts our ability to, among other things:

- Make cash distributions;
- Incur indebtedness;
- Create liens;
- Make investments;
- Engage in transactions with affiliates;

- Make any material change to the nature of our business;
- Dispose of assets; and
- Merge with another company or sell all or substantially all of our assets.

Furthermore, our credit agreement contains covenants requiring us to maintain certain financial ratios. The provisions of our credit agreement may affect our ability to obtain future financing for and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit agreement could result in an event of default which could enable our lenders, subject to the terms and conditions of our credit agreement, to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, our lenders could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, defaults under our other debt instruments, if any, may be triggered and our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- Our ability to obtain additional financing, if necessary, for working capital, capital expenditures or other purposes may be impaired, or such financing may not be available on favorable terms;
- Our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- We may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- Our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to maintain our indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business, acquisitions, investments or capital expenditures, selling assets or issuing equity. We may not be able to affect any of these actions on satisfactory terms or at all.

Changes in currency exchange rates could adversely affect our operating results.

Because we are a U.S. dollar reporting company and also conduct a portion of our operations in Canada in the Canadian dollar, we are exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of our earnings, cash flow and partners capital under applicable accounting rules.

Warmer weather conditions during winter could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Weather conditions during winter have an impact on the demand for both heating oil, residual fuel oil and natural gas. Because we supply distributors whose customers depend on heating oil, residual fuel oil and natural gas during the winter, warmer-than-normal temperatures during the first and fourth calendar quarters in one or more regions in which we operate can decrease the total volume we sell and the adjusted gross margin realized on those sales and, consequently, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act), was enacted that establishes U.S. federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the Commodities Futures Trading Commission (CFTC), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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In October 2010, pursuant to its rulemaking under the Act, the CFTC issued rules to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September of 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception to the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, the Act requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact our liquidity and reduce cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules for uncleared swaps are not yet final and their impact on us is not yet clear.

The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivative contracts has adjusted. The Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have material adverse effect on our financial condition, results of operations and cash available for distributions to our unitholders.

In addition, other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

Our risk management policies, processes and procedures cannot eliminate all commodity price risk or basis risk, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. In addition, any noncompliance with our risk management policies, processes and procedures could result in significant financial losses.

While our risk management policies, processes and procedures are designed to limit commodity price risk, some degree of exposure to unforeseen fluctuations in market conditions remains. For example, we change our hedged position daily in response to movements in our inventory. If we overestimate or underestimate our sales from inventory, we may be unhedged for the amount of the overestimate or underestimate.

In general, basis risk describes the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of a like commodity at a different time or place. Basis may reflect price differentiation associated with different time periods, qualities or grades, or locations and is typically calculated based on the price difference between the cash or spot price of a commodity and the prompt month futures or swaps contract price of the most comparable commodity. For

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example, if NYMEX heating oil, which is based on New York Harbor delivery, was used to hedge our commodity risk for heating oil purchases, we could have location basis risk if the deliveries were made in a different location such as in Boston. An example of quality or grade basis risk would be the use of heating oil contracts to hedge diesel fuel. The potential exposure from basis risk is in addition to any impact that market pricing structure may have on our results. Basis risk cannot be entirely eliminated and basis exposure can adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

We monitor policies, processes and procedures designed to prevent unauthorized trading and to maintain substantial balance between purchases and sales or future delivery obligations. We can provide no assurance, however, that these steps will detect and/or prevent all violations of such risk management policies, processes and procedures, particularly if deception or other intentional misconduct is involved.

We are exposed to risks of loss in the event of nonperformance by our customers, suppliers and counterparties.

Some of our customers, suppliers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. A tightening of credit in the financial markets or an increase in interest rates may make it more difficult for our customers, suppliers and counterparties to obtain financing and, depending on the degree to which it occurs, there may be a material increase in the nonpayment or other nonperformance by our customers, suppliers and counterparties. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with these third parties. A material increase in the nonpayment or other nonperformance by our customers, suppliers and/or counterparties could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Additionally, our access to trade credit support could diminish or become more expensive. Our ability to continue to receive sufficient trade credit on commercially acceptable terms could be adversely affected by, among other things, fluctuations in refined product, natural gas and renewable fuel prices or disruptions in the credit markets.

We are exposed to performance risk in our supply chain.

We rely upon our suppliers to timely produce the volumes and types of refined products for which they contract with us. In the event one or more of our suppliers does not perform in accordance with its contractual obligations, we may be required to purchase product on the open market to satisfy forward contracts we have entered into with our customers in reliance upon such supply arrangements. We purchase refined products from a variety of suppliers under term contracts and on the spot market. In times of extreme market demand, we may be unable to satisfy our supply requirements. Furthermore, a portion of our supply comes from other countries, which could be disrupted by political events. In the event such supply becomes scarce, whether as a result of political events, natural disaster, logistical issues associated with delivery schedules or otherwise, we may not be able to satisfy our supply requirements. If any of these events were to occur, we may be required to pay more for product that we purchase on the open market, which could result in financial losses and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Some of our competitors have capital resources many times greater than ours and control greater supplies of refined products and natural gas. Competitors able to supply our customers with those products and services at a lower price could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our competitors include terminal companies, major integrated oil companies and their marketing affiliates and independent marketers of varying size, financial resources and experience. Some of our competitors are substantially larger than us, have capital resources many times greater than ours, control greater supplies of refined products and natural gas than us and/or control substantially greater storage capacity than us. If we are

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unable to compete effectively, we may lose existing customers or fail to acquire new customers, which could have a material adverse effect on our business, financial condition, results of operations and distributable cash flow. For example, if a competitor attempts to increase market share by reducing prices or offering alternative energy sources, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected. We may not be able to compete successfully with these companies.

Some of our heating oil and residual fuel oil volumes are subject to customers switching or converting to natural gas, which could result in loss of customers and, in turn, could have an adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our heating oil and residual fuel oil businesses compete for customers with suppliers of natural gas. During a period of increasing heating oil prices relative to natural gas prices, heating oil users may convert to natural gas. Similarly, during a period of increasing residual fuel oil prices relative to natural gas prices, customers who have the ability to switch from residual fuel oil to natural gas (dual-fuel customers), may switch and other end users may convert to natural gas.

Such switching and conversions could reduce our sales of heating oil and residual fuel oil and could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Energy efficiency, new technology and alternative energy sources could reduce demand for our products and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Increased conservation, technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, fuel efficient motor vehicles and the availability of alternative energy sources have adversely affected the demand for some of our products, particularly home heating oil and residual fuel oil. Future conservation measures, technological advances in heating, conservation, energy generation or other devices, and increased availability and use of alternative energy sources, including as a result of government regulation, might reduce demand and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Security breaches and other disruptions could compromise our information and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our customers and employees, in our data centers and on our networks. The secure maintenance of this information is critical to our operations. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disrupt our operations and the services we provide to customers, and damage our reputation, cause a loss of confidence in our products and services, which could adversely affect our business/operating margins, revenues and competitive position.

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A principal focus of our business strategy is to grow and expand our business through acquisitions. If we do not make acquisitions on economically acceptable terms, our future growth may be limited and any acquisitions we make may reduce, rather than increase, our cash generated from operations on a per unit basis.

A principal focus of our business strategy is to grow and expand our business through acquisitions. Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated per unit from operations. If we are unable to make accretive acquisitions, either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, such acquisitions may nevertheless result in a decrease in the cash generated from operations per unit.

Any acquisition involves potential risks, including, among other things:

- Mistaken assumptions about volumes, cash flows, net sales and costs, including synergies;
- An inability to successfully integrate the businesses we acquire;
- An inability to hire, train or retain qualified personnel to manage and operate our newly acquired assets;
- The assumption of unknown liabilities;
- Limitations on rights to indemnity from the seller;
- Mistaken assumptions about the overall costs of equity or debt used to finance an acquisition;
- The diversion of management s and employees attention from other business concerns;
- Unforeseen difficulties operating in new product areas or new geographic areas; and
- Customer or key employee losses at the acquired businesses.

A portion of our net sales is generated under contracts that must be renegotiated or replaced periodically. If we are unable to successfully renegotiate or replace these contracts, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected.

Most of our contracts with our refined products customers are for a single season or on a spot basis, while most of our contracts with our natural gas customers are for a term of one year or less. As these contracts and our materials handling contracts expire from time to time, they must be renegotiated or replaced. We may be unable to renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. Whether these contracts are successfully renegotiated or replaced is often subject to factors beyond our control. Such factors include fluctuations in refined product and natural gas prices, counterparty ability to pay for or accept the contracted volumes and a competitive marketplace for the services we offer. While our materials handling contracts are generally long-term, they are also subject to periodic renegotiation or replacement. If we cannot successfully renegotiate or replace any of our contracts, or if we renegotiate or replace them on less favorable terms, net sales and margins from these contracts could decline and our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected.

Due to our lack of geographic diversification, adverse developments in the terminals we use or in our operating areas would adversely affect our results of operations and distributable cash flow.

We rely primarily on sales generated from products distributed from the terminals we own, control or operate to which we have access. Furthermore, our operations are largely located in the Northeast United States.

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Due to our lack of geographic diversification, an adverse development in the businesses or areas in which we operate, including adverse developments due to catastrophic events or weather and decreases in demand for refined products, could have a significantly greater impact on our results of operations and distributable cash flow than if we operated in more diverse locations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be able to maintain adequate insurance coverage.

We are not fully insured against all risks incident to our business. Our operations are subject to many operational hazards and unforeseen interruptions inherent in our business, including:

- Damage to storage facilities and other assets caused by tornadoes, hurricanes, floods, earthquakes, fires, explosions, extreme weather conditions and other natural disasters;
- Acts or threats of terrorism;
- Unanticipated equipment and mechanical failures at our facilities;
- Disruptions in supply infrastructure or logistics and other events beyond our control;
- Operator error; and
- Environmental pollution or other environmental issues.

If any of these events were to occur, we could incur substantial losses because of personal injury or loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental damage resulting in curtailment or suspension of our related operations.

We may be unable to maintain or obtain insurance of the type and amount we believe to be appropriate for our business at reasonable rates or at all. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased over the past four years and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Certain types of risks, such as fines and penalties, or remediation or damages claims from environmental pollution, are either not covered by insurance or applicable insurance may be unavailable for particular claims based on exclusions or limitations in the policies. If we were to incur a significant liability for which we were not fully insured, it could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our terminalling and materials handling operations are subject to federal, state and local laws and regulations relating to environmental protection and operational safety that require us to incur substantial costs and that may become more stringent over time.

The risk of substantial environmental costs and liabilities is inherent in terminalling and materials handling operations, and we may incur substantial environmental costs and liabilities. In particular, our terminalling operations involve the receipt, storage and redelivery of refined products and are subject to stringent federal, state and local laws and regulations regulating product quality specifications and other environmental matters including the discharge of materials into the environment, or otherwise relating to the protection of the environment, operational safety and related matters. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to maintain and upgrade equipment and facilities. Further, we may incur increased costs because of stricter pollution control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. We utilize a number of terminals that are owned and operated by third parties who are also subject to these stringent federal, state and local environmental laws in their operations. Compliance with these requirements could increase the cost of doing business with these facilities and there can be no assurances as to the timing and type of such changes or what the ultimate costs might be. Moreover, the failure to comply with these requirements can expose our operations to fines, penalties, permit revocation and injunctive relief, including limits or prohibitions on some or all of our operations.

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The risks of spills and releases and the associated liabilities for investigation, remediation and third-party claims, if any, are inherent in terminalling operations, and the liabilities that we incur may be substantial.

Our operation of refined products terminals and storage facilities is inherently subject to the risks of spills, discharges or other inadvertent releases of petroleum or other hazardous substances. If any of these events have previously occurred or occur in the future, whether in connection with any of our storage facilities or terminals, any other facility to which we send or have sent wastes or by-products for treatment or disposal or on any property which we own or have owned, we could be liable for all costs, jointly and severally, and administrative, civil and criminal penalties associated with the investigation and remediation of such facilities under federal, state and local environmental laws or the common law. We may also be held liable for damages to natural resources, personal injury or property damage claims from third parties, including the owners of properties located near our terminals and those with whom we do business, alleging contamination from spills or releases from our facilities or operations. Even if we are insured against certain or all of such risks, we may be responsible for all such costs to the extent our insurers or indemnitors do not fulfill their obligations to us. The payment of such costs or penalties could be significant and have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Increased regulation of greenhouse gas emissions could result in increased operating costs and reduced demand for refined products as a fuel source, which could in turn reduce demand for our products and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Combustion of fossil fuels, such as the refined products we sell, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, the Environmental Protection Agency, or the EPA, published its findings that emissions of carbon dioxide and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes, and the EPA has begun to regulate greenhouse gases, or GHG, emissions pursuant to the Clean Air Act. Many states and regions have adopted GHG initiatives and it is possible that U.S. federal legislation could be adopted in the future to restrict GHG emissions.

There are many regulatory approaches currently in effect or being considered to address greenhouse gases, including possible future U.S. treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program and regulation by the EPA. Future international, federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with refined products consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs could result in reduced demand for refined products and some customers switching to alternative sources of fuel which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Per the *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances, CQLR c Q-2, r.46.1*, as of January 1, 2015, any person or municipality that distributes in Québec fossil fuels whose combustion meets or exceeds the established annual greenhouse gas (GHG) emission threshold is covered by the cap-and-trade (C&T) system. Emitters regulated by the C&T system are required to cover their GHG emissions until at least 2020 or until December 31 following their third consecutive GHG emission report that falls below the requisite emission threshold.

Kildair, as a distributor of fuels and combustibles covered by the C&T system, as of January 1st, 2015, does not qualify to receive free GHG emission units. Rather, Kildair is required to purchase all emission allowances needed to cover emissions attributable to the combustion of the fossil fuels they sell for consumption in Québec at government auctions or on the Western Climate Initiative (WCI) carbon market. Additionally, Kildair may purchase offset credits that comply with Quebec laws and regulations. To comply with these laws and regulations, Kildair must incur costs to purchase credits that allow Kildair to continue operations at their current level. Increased costs may result in increased prices for Kildair s products or decreased profitability. Increased product price could result in a reduction of demand for Kildair s product and therefore reduce our revenues. Additional risks include the inability to acquire the required amount of emission allowances or credits to offset GHG emissions which would subject Kildair to various fines.

We are subject to federal, state and local laws and regulations that govern the product quality specifications of the refined products we purchase, store, transport and sell.

Various federal, state and local government agencies have the authority to prescribe specific product quality specifications to the sale of commodities. Changes in product quality specifications, such as reduced sulfur content in refined products, or other more stringent requirements for fuels, could reduce our ability to procure product and require us to incur additional handling costs and capital expenditures. If we are unable to procure product or recover these costs through increased sales, we may not be able to meet our financial obligations.

We and our subsidiaries depend on unionized labor for our operations in Lawrence, Mt. Vernon; Albany, New York; Providence, Rhode Island; and Sorel-Tracy Quebec, Canada. We are also in negotiations with two additional unions for the Bronx, NY terminal as part of the Castle acquisition. Work stoppages or labor disturbances at these facilities could disrupt our business.

Work stoppages or labor disturbances by our unionized labor force could have an adverse effect on our financial condition, results of operations and distributable cash flow. In addition, employees who are not currently represented by labor unions may seek representation in the future, and renegotiation of collective bargaining agreements may result in agreements with terms that are less favorable to us than our current agreements.

We rely on our information technology systems to manage numerous aspects of our business, and a disruption of these systems could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

We depend on our information technology, or IT, systems to manage numerous aspects of our business and to provide analytical information to management. Our IT systems are an essential component of our business and growth strategies, and a serious disruption to our IT systems could limit our ability to manage and operate our business efficiently. These systems are vulnerable to, among other things, damage and interruption from power loss or natural disasters, computer system and network failures, loss of telecommunication services, physical and electronic loss of data, security breaches and computer viruses. We employ back-up IT facilities and have disaster recovery plans; however, these safeguards may not entirely prevent delays or other complications that could arise from an IT systems failure, a natural disaster or a security breach. Significant failure or interruption in our IT systems could cause our business and competitive position to suffer and damage our reputation, which would adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Risks Inherent in an Investment in Us

It is our business strategy to distribute in increasing amounts our distributable cash flow, which could limit our ability to grow and make acquisitions.

We expect that we will distribute in increasing amounts our distributable cash flow to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute most of our distributable cash flow, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those

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additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our credit agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the cash that we have available to distribute to our unitholders.

Axel Johnson indirectly controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Axel Johnson, may have conflicts of interest with us and have limited duties to us and our common unitholders, and they may favor their own interests to the detriment of us and our common unitholders.

As of March 9, 2015, Axel Johnson, through its ownership of Sprague Holdings, indirectly owns a 57.4% limited partner interest in us and indirectly owns and controls our general partner. Although our general partner has a fiduciary duty to manage us in good faith, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, Sprague Holdings, which is a wholly owned subsidiary of Axel Johnson. Furthermore, certain directors and officers of our general partner are directors and/or officers of affiliates of our general partner. Conflicts of interest may arise between our general partner and its affiliates, including Axel Johnson, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates, including Axel Johnson, over the interests of our common unitholders. These conflicts include, among others, the following situations:

- Our general partner is allowed to take into account the interests of parties other than us, such as its affiliates, including Axel Johnson, in resolving conflicts of interest, which has the effect of limiting its duty to our unitholders.

- Affiliates of our general partner, including Axel Johnson and Sprague Holdings, may engage in competition with us.

- Neither our partnership agreement nor any other agreement requires Axel Johnson or Sprague Holdings to pursue a business strategy that favors us, and Axel Johnson s directors and officers have a fiduciary duty to make decisions in the best interests of the stockholder s of Axel Johnson.

- Some officers of our general partner who provide services to us devote time to affiliates of our general partner.

- Our partnership agreement limits the liability of and reduces the duties owed by our general partner to us and our common unitholders, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the creation, reductions or increases of cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders, including distributions on our subordinated units, and to the holders of the incentive distribution rights, as well as the ability of the subordinated units to convert to common units.

Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces distributable cash flow. Such determination can affect the amount of distributable cash flow, including distributions on our subordinated units, and to the holders of the incentive distribution rights, as well as the ability of the subordinated units to convert to common units. Our partnership agreement does not limit the amount of maintenance capital expenditures that our general partner can cause us to make.

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Our partnership agreement and the services agreement allow our general partner to determine, in good faith, the expenses that are allocable to us. Our partnership agreement and the services agreement do not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons, including affiliates of our general partner, who perform services for us or on our behalf.

Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

Our partnership agreement permits us to distribute up to $25.0 million as distributable cash flow, even if it is generated from sources that would otherwise constitute capital surplus, and this cash may be used to fund distributions on our subordinated units or the incentive distribution rights.

Our partnership agreement does not restrict our general partner from entering into additional contractual arrangements with any of its affiliates on our behalf.

Our general partner intends to limit its liability regarding our contractual and other obligations.

Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 80% of all outstanding common units.

Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Sprague Holdings, or any transferee holding a majority of the incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including their executive officers, directors and owners. Other than as provided in our omnibus agreement, any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Our general partner intends to limit its liability regarding our obligations.

Other than under our credit agreement, our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s duty to act in good faith, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of distributable cash flow otherwise available for distribution to our unitholders.

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Our partnership agreement limits our general partner s duties to our unitholders.

Our partnership agreement contains provisions that modify and reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- How to allocate business opportunities among us and its other affiliates;
- Whether to exercise its limited call right;
- How to exercise its voting rights with respect to any units it owns;
- Whether to exercise its registration rights with respect to any units it owns; and
- Whether to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- Provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law or any other law, rule or regulation, or at equity;
- Provides that a determination, other action or failure to act by our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) will be deemed to be in good faith unless our general partner, the board of directors of our general partner or any committee thereof

believed such determination, other action or failure to act was adverse to the interests of the partnership;

Provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;

Provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

Provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is:

(1) Approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or

(2) Approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Cost reimbursements and fees due to our general partner and its affiliates for services provided to us or on our behalf, which may be determined in our general partner s sole discretion, may be substantial and will reduce our distributable cash flow.

Under our partnership agreement, prior to making any distribution on the common units, our general partner and its affiliates shall be reimbursed for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Pursuant to the terms of the services agreement, our general partner will agree to provide certain general and administrative services and operational services to us, and we will agree to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Our general partner and its affiliates also may provide us other services for which we may be charged fees as determined by our general partner. Our partnership agreement and the services agreement do not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Payments to our general partner and its affiliates may be substantial and will reduce the amount of distributable cash flow.

Unitholders have limited voting rights and, even if they are dissatisfied, cannot remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by Sprague Holdings, a wholly-owned subsidiary of Axel Johnson and the sole member of our general partner. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 ⅔% of all outstanding common units and subordinated units voting together as a single class is required to remove our general partner. As of March 9, 2015, Sprague Holdings owns 57.4% of the common units and subordinated units. If our general partner is removed without cause during the subordination period and no units held by the holders of our subordinated units or their affiliates are voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests, and by eliminating existing arrangements, if any. Cause is narrowly defined to mean that a court of competent jurisdiction has

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entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of our business.

Furthermore, unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units resulting in ownership of at or in excess of such levels with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of Sprague Holdings to transfer its membership interest in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to control the decisions taken by the board of directors and officers.

The incentive distribution rights held by Sprague Holdings may be transferred to a third party without unitholder consent.

Sprague Holdings may transfer the incentive distribution rights to a third party at any time without the consent of our unitholders. If Sprague Holdings transfers the incentive distribution rights to a third party but retains its ownership interest in our general partner, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if Sprague Holdings had retained ownership of the incentive distribution rights. For example, a transfer of incentive distribution rights by Sprague Holdings could reduce the likelihood of Axel Johnson accepting offers made by us relating to assets owned by it, as Axel Johnson would have less of an economic incentive to grow our business, which in turn may impact our ability to grow our asset base.

We may issue additional units without unitholder approval, which would dilute unitholder interests.

At any time, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Further, neither our partnership agreement nor our credit agreement prohibits the issuance of equity securities that may effectively rank senior to our common units. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- Our unitholders proportionate ownership interest in us will decrease;

- The amount of distributable cash flow on each unit may decrease;

Because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution borne by our common unitholders will increase;

The ratio of taxable income to distributions may increase;

The relative voting strength of each previously outstanding unit may be diminished; and

The market price of our common units may decline.

Sprague Holdings may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of March 9, 2015, Sprague Holdings and its subsidiaries held 2,034,378 common units and 10,071,970 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period (which could occur as early as December 31, 2016) and may convert earlier under certain circumstances. Additionally, we have agreed to provide Sprague Holdings with certain registration rights (which may facilitate the sale by Sprague Holdings of its common and subordinated units into the public markets). The sale of these units in the public or private markets, or the perception that such sales might occur, could have an adverse impact on the price of the common units or on any trading market that may develop.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Our general partner s discretion in establishing cash reserves may reduce the amount of distributable cash flow that we distribute.

The partnership agreement permits the general partner to reduce the amount of distributable cash flow distributed to our unitholders by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners.

Our general partner may cause us to borrow funds in order to make cash distributions, even where the purpose or effect of the borrowing benefits the general partner or its affiliates.

In some instances, our general partner may cause us to borrow funds from its affiliates, including Axel Johnson, or from third parties in order to permit the payment of cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make a distribution on the subordinated units, to make incentive distributions or to hasten the expiration of the subordination period.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of our common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons. As a result, you may be required to sell your common units at an undesirable time or price, including at a price below the then-current market price, and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of March 9,2015, Sprague Holdings and its affiliates owned approximately 18.5% of our common units. At the end of the subordination period (which could occur as early as December 31, 2016), assuming no additional issuances of common units (other than upon the conversion of the subordinated units), our general partner and its affiliates will own approximately 57.4% of our common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some jurisdictions. You could be liable for our obligations as if you were a general partner if a court or government agency were to determine that:

- We were conducting business in a state but had not complied with that particular state s partnership statute; or

- Your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes control of our business.

A restatement of net income or a reversal or change of estimates affecting net income made after the end of the subordination period but affecting net income during the subordination period will not retroactively affect the conversion of the subordinated units even if we would not have had sufficient distributable cash flow based on such restated or adjusted net income to permit conversion.

Our subordinated units will convert into common units upon the satisfaction of certain tests involving the calculation of distributable cash flow on a historical basis. Distributable cash flow is calculated based on net income, which is a GAAP measure. If net income for a period during the subordination period is restated after the end of the subordination period or if estimates affecting net income made during the subordination period are reversed or changed after the end of the subordination period, it will not retroactively affect the conversion of subordinated units even if we would not have had sufficient distributable cash flow during the subordination period based on such restated or adjusted net income to permit conversion.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, or the Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Sprague Holdings, or any transferee holding a majority of the incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the incentive distribution rights, without the approval of the conflicts committee of the board of directors of our general partner or the holders of our common units. This could result in lower distributions to our unitholders.

The holder or holders of a majority of the incentive distribution rights (currently Sprague Holdings) have the right, in their discretion and without the approval of the conflicts committee of the board of directors of our general partner or the holders of our common units, at any time when there are no subordinated units outstanding and the holders received distributions on their incentive distribution rights at the highest level to which they are entitled (50.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. Sprague Holdings has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as Sprague Holdings relative to resetting target distributions.

In the event of a reset of target distribution levels, the holders of the incentive distribution rights will be entitled to receive a number of common units equal to the number of common units that would have entitled the holders to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in the prior two quarters. We anticipate that Sprague Holdings would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that Sprague Holdings or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that they would have otherwise received had we not issued new common units in connection with resetting the target distribution levels.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

As a limited partnership, we are not required to have a majority of independent directors on our general partner s board of directors or to establish a compensation committee or a nominating and corporate governance committee, as is required for other NYSE-listed entities. Accordingly, unitholders do not have the same protections afforded to certain entities, including most corporations that are subject to all of the NYSE corporate governance requirements.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for U.S. federal income tax purposes then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to the limited partners. Because a tax would be imposed upon us as a corporation, our cash available for distributions would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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Our partnership agreement provides that if a law is enacted, or existing law is modified or interpreted in a manner, that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state, local or non-U.S. income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our distributable cash flow.

We are currently subject to entity level taxes and fees in a number of states, and such taxes and fees will reduce the distributable cash flow. Changes in current state laws may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such additional taxes on us by other states in which we do business will further reduce the distributable cash flow available for distribution to unitholders.

Notwithstanding our treatment for U.S. federal income tax purposes, we are subject to certain non-U.S. taxes. If a taxing authority were to successfully assert that we have more tax liability than we anticipate or legislation were enacted that increased the taxes to which we are subject, our distributable cash flow could be further reduced.

A material amount of our business operations and subsidiaries are subject to income, withholding and other taxes in the non-U.S. jurisdictions in which they are organized or from which they receive income, reducing the amount of our distributable cash flow. In computing our tax obligation in these non-U.S. jurisdictions, we are required to take various tax accounting and reporting positions on matters that are not entirely free from doubt and for which we have not received rulings from the governing tax authorities, such as whether withholding taxes will be reduced by the application of certain tax treaties. Upon review of these positions, the applicable authorities may not agree with our positions. A successful challenge by a tax authority could result in additional tax being imposed on us. In addition, changes in our operations or ownership could result in higher than anticipated tax being imposed in jurisdictions in which we are organized or from which we receive income. Any such increases in tax imposed on us would further reduce our distributable cash flow. Although these taxes may be properly characterized as foreign income taxes, unitholders may not be able to credit them against their liability for U.S. federal income taxes on their share of our earnings.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Fiscal Year 2016 Budget proposed by the President recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS has been considering changes to its private letter ruling policy concerning which activities give rise to qualifying income within the meaning of section 7704 of the Code. The implementation of changes to this policy could include the modification or revocation of existing rulings, including ours.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. federal income tax purposes.

We will be considered to have terminated our partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period.

Sprague Holdings currently directly and indirectly owns more than 50% of the total interests in our capital and profits interests. Therefore, a transfer by Sprague Holdings of all or a portion of its interests in us, along with transfers by other unitholders, could result in a termination of our partnership for U.S. income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead, we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder sells common units, such unitholder will recognize gain or loss equal to the difference between the amount realized and the unitholder s tax basis in those units. Because distributions in excess of the unitholder s allocable share of our net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units being sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price received is less than the unitholder s original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts, or IRAs, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file U.S. federal tax returns and pay tax on its share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

If a tax authority contests the tax positions we take, the market for our common units may be adversely affected and the cost of any such contest will reduce our distributable cash flow.

Tax authorities may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with a tax authority may materially and adversely affect the market for our common units and the price at which they trade. Our costs of any contest with a tax authority will be borne indirectly by our unitholders and our general partner because the costs will reduce our distributable cash flow.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Due to a number of factors including our inability to match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and, although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g. a loan to a short seller to cover a short sale of common units) may be considered to have disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and could be required to recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, such unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may be required to recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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Unitholders may be subject to state and local taxes and return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business and own property in numerous states, in the United States most of which impose a personal income tax as well as an income tax on corporations and other entities. We may own property or conduct business in other U.S. states or non-U.S. countries in the future. It is the unitholder s responsibility to file all U.S. federal, state, local and non-U.S. tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The following tables set forth information with respect to our 19 owned, operated and/or controlled terminals.

Liquids Storage Terminal	Number of Storage Tanks (1)	Storage Tank Capacity (Bbls) (1)	Principal Products
Sorel-Tracy Quebec, Canada (2)	27	3,282,600	refined products; asphalt; crude oil
Searsport, ME	17	1,139,700	refined products; caustic soda; asphalt
South Portland, ME	26	1,122,100	refined products; asphalt; clay slurry
Bridgeport, CT (3)	11	1,120,600	refined products
Albany, NY	11	1,104,500	refined products
East Providence, RI (4)	9	1,004,600	refined products
Newington, NH: River Road	28	941,800	refined products; tallow
Bronx, NY (5)	17	907,500	refined products; asphalt
Newington, NH: Avery Lane	11	679,000	refined products; asphalt
New Haven, CT (6)	15	657,700	refined products
Quincy, MA	9	657,000	refined products
Providence, RI	4	484,000	refined products; asphalt
Everett, MA	4	317,600	asphalt
Quincy, MA: TRT (7)	4	304,200	refined products
Oswego, NY	3	163,700	refined products; asphalt
New Bedford, MA (8)	2	85,900	refined products
Mount Vernon, NY	7	72,100	refined products
Stamford, CT	3	46,600	refined products
Total	208	14,091,200	

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Dry Storage Terminal	Number of Storage Pads and Warehouses	Storage Capacity (Square Feet)	Principal Products and Materials
Newington, NH: River Road (9)	3 pads	431,000	salt; gypsum
Searsport, ME	3 warehouses;	101,000	break bulk; salt; petroleum coke;
	7 pads	310,000	heavy lift
Portland, ME (10)	7 warehouses;	215,000	break bulk; coal
	4 pads	180,000	
South Portland, ME	3 pads	230,000	salt; coal
Providence, RI	1 pad	75,000	salt
	10 warehouses;		
Total	18 pads	1,542,000	

(1) We also have an aggregate of approximately 2.3 million barrels of additional storage capacity attributable to 47 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional storage capacity were desired, additional time and capital would be required to bring any of such storage tanks back into service.
(2) We acquired the Sorel-Tracy, Quebec Canada terminal on December 9, 2014
(3) We acquired the Bridgeport terminal on July 31, 2013.
(4) These tanks are controlled via a petroleum storage services agreement whose terms include an initial term through April 30, 2019, with mutual rights of termination beginning April 16, 2016.
(5) We acquired the Bronx, NY terminal on December 8, 2014
(6) These tanks are controlled via a storage and thruput agreement with initial term through July 2, 2019. Term may be extended under mutual agreement.
(7) Operating assets and real estate are leased from Twin Rivers Technology L.P., an unaffiliated third party.
(8) Operating assets and real estate are leased from Sprague Massachusetts Properties LLC, a wholly-owned subsidiary of Sprague Holdings. The New Bedford terminal is subject to a purchase and sale agreement pursuant to which a third party has agreed to acquire the terminal from Sprague Massachusetts Properties LLC. The acquisition is subject to certain conditions that are beyond the control of Sprague Massachusetts Properties LLC. In the event that such sale is consummated, our terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC will automatically terminate. Subject to those conditions, the acquisition may be consummated on or before January 5, 2016.
(9) The terminal also has two silos capable of storing a total of approximately 26,000 tons of cement.
(10) Real estate and two storage buildings are leased from Merrill Industries Inc., an unaffiliated third party, and the balance of the assets are owned by us.

Item 3. 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 4. Mine Safety Disclosures

Not applicable.

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Part II

Item 5. Market for Our Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our public common units began trading on the NYSE under the symbol SRLP on October 25, 2013. Prior to that time, there was no public market for our securities. As of March 9, 2015, Sprague Holdings and its subsidiaries owned 2,034,378 common units and 10,071,970 subordinated units, which together constitute a 57.4% ownership interest in us. During the year ended December 31, 2013, we issued 8,500,000 common units to the public in connection with our IPO and 6,666 restricted units in accordance with the 2013 Long Term Incentive Plan for Director compensation. During the year ended December 31, 2014, we issued 706,263 common units in connection with business acquisitions and 27,401 common units in connection with the 2013 Long Term Incentive Plan for Employee and Director compensation. As of March 9, 2015, the closing market price for our common units was $24.69 per unit and there were approximately 6 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record.

The following table sets forth the range of the high and low closing prices of our common units and cash distributions to common unitholders for the period from October 25, 2013, the date our shares began trading.

Quarter Ended	Sales Price per Common Unit High	Sales Price per Common Unit Low	Quarterly Cash Distribution per Unit	Record Date	Distribution Date
December 31, 2013 (1)(2)	$ 18.24	$ 16.89	$ 0.2825	February 10, 2014	February 14, 2014
March 31, 2014	$ 20.75	$ 17.68	$ 0.4125	May 9, 2014	May 15, 2014
June 30, 2014	$ 27.30	$ 19.05	$ 0.4275	August 8, 2014	August 14, 2014
September 30, 2014	$ 26.93	$ 21.29	$ 0.4425	November 10, 2014	November 14, 2014
December 31, 2014	$ 27.02	$ 19.00	$ 0.4575	February 9, 2015	February 13, 2015

(1) Sales price per common unit from October 25, 2013, the commencement date of trading.
(2) Quarterly cash distribution per unit was prorated for the days from October 30, 2013, the closing date of the IPO, through December 31, 2013.

Certain Information from Our Partnership Agreement

Set forth below is a summary of certain provisions of our partnership agreement that relate to cash distributions and incentive distribution rights.

Our Cash Distribution Policy

It is our intent to distribute, within 45 days after the end of each fiscal quarter, the minimum quarterly distribution of $0.4125 per unit on all our units ($1.65 per unit on an annualized basis) to the extent we have sufficient cash from our operations after the establishment of cash reserves and payment of our expenses. The board of directors of our general partner will determine the amount of our quarterly distributions and may change our distribution policy at any time. The board of directors of our general partner may determine to reserve or reinvest excess cash in order to permit gradual or consistent increases in quarterly distributions and may borrow to fund distributions in quarters when we generate less distributable cash flow than necessary to sustain or grow our cash distributions per unit.

There is no guarantee that unitholders will receive quarterly cash distributions from us. We do not have a legal obligation to pay distributions at our minimum quarterly distribution rate or at any other rate. Uncertainties regarding future cash distributions to our unitholders include, among other things, the following factors:

- Our cash distribution policy may be affected by restrictions on distributions under our credit agreement as well as by restrictions in future debt agreements that we enter into. Specifically, our credit agreement contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions or if we are otherwise in default under our credit agreement, we may be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.

Our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy.

Under Section 17-607 of the Delaware Act we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

We may lack sufficient cash to make distributions to our unitholders due to a number of operational, commercial and other factors or increases in our operating costs, general and administrative expenses, principal and interest payments on our outstanding debt and working capital requirements.

If we make distributions out of capital surplus, as opposed to distributable cash flow, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. We do not anticipate that we will make any distributions from capital surplus.

Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of future indebtedness, applicable state partnership, limited liability company and corporate laws and other laws and regulations.

See Item 1A. Risk Factors Risk Related to our Business.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interest.

Subordinated Units

Sprague Holdings owns, directly or indirectly, all of our subordinated units. The principal difference between our common units and subordinated units is that during the period referred to in our partnership agreement as the subordination period , the common units have the right to receive distributions of cash from distributable cash flow each quarter in an amount equal to $0.4125 per common unit, which is the amount defined in our partnership agreement as the minimum quarterly distribution, 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. Furthermore, no arrearages will accrue or be paid on the subordinated units.

Upon expiration of the subordination period, any outstanding arrearages in payment of the minimum quarterly distribution on the common units will be extinguished (not paid), each outstanding subordinated unit will immediately convert into one common unit and will thereafter participate pro rata with the other common units in distributions.

Incentive Distribution Rights

Sprague Holdings currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from distributable cash flow in excess of $0.61875 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that our sponsor may receive on any limited partner units that it owns.

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Item 6. Selected Financial Data

The following table presents selected historical consolidated financial and operating data of the Partnership and our predecessor, Sprague Operating Resources LLC, as of the dates and for the periods indicated. The selected historical financial data as of and for the year ended December 31, 2014 are derived from the Partnership s 2014 audited Consolidated and Combined Financial Statements. The selected historical financial data as of and for the year ended December 31, 2013 includes the combined results of the Predecessor through October 29, 2013 and the Partnership for the period from October 30, 2013 through December 31, 2013, all derived from the Partnership s 2013 audited Consolidated and Combined Financial Statements. The selected historical consolidated financial data presented as of and for the years ended December 31, 2012, 2011 and 2010 are derived from the audited consolidated financial statements of Sprague Operating Resources LLC.

On December 9, 2014, the Partnership acquired all of the equity interests in Kildair through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties LLC. As this transaction represented a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson.

The following table presents the non-GAAP financial measure adjusted EBITDA, which we use in our business as an important supplemental measure of our performance. We define and explain this measure under Non-GAAP Financial Measures on page 46 and reconcile it to net income (loss), its most directly comparable financial measure calculated and presented in accordance with GAAP.

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	Years Ended December 31,				
	2014	2013	2012 Predecessor	2011 Predecessor	2010 Predecessor
	(in thousands, except unit data and operating data)				
Statements of Operations Data:					
Net sales	$ 5,069,762	$ 4,683,349	$ 4,043,907	$ 3,797,427	$ 2,817,191
Cost of products sold (exclusive of depreciation and amortization)	4,755,031	4,554,188	3,922,352	3,638,717	2,676,301
Operating expenses	62,993	53,273	47,054	42,414	41,102
Selling, general and administrative	76,420	55,210	46,449	46,292	40,625
Write-off of deferred offering costs (1)			8,931		
Depreciation and amortization	17,625	16,515	11,665	10,140	10,531
Total operating costs and expenses	4,912,069	4,679,186	4,036,451	3,737,563	2,768,559
Operating income	157,693	4,163	7,456	59,864	48,632
Gain on acquisition of business			1,512	6,016	
Other income (expense)	(288)	568	(160)		894
Interest income	569	604	534	755	503
Interest expense	(29,651)	(30,914)	(23,960)	(24,049)	(21,897)
Income (loss) before income taxes and equity in net (loss) income of foreign affiliate	128,323	(25,579)	(14,618)	42,586	28,132
Income tax (provision) benefit (2)	(5,509)	(4,259)	2,796	(16,636)	(10,288)
Income (loss) before equity in net (loss) income of foreign affiliate	122,814	(29,838)	(11,822)	25,950	17,844
Equity in net (loss) income in foreign affiliate			(1,009)	3,622	(2,123)
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)	$ 29,572	$ 15,721
Less: Predecessor (income) through October 29, 2013		(2,734)			
Less: (Income) loss attributable to Kildair from October 29, 2013 through December 8, 2014 (Note 1)	(4,080)	2,338			
Limited partners interest in net income (loss) (3)	$ 118,734	$ (30,234)			
Net income (loss) per limited partner common units basic (3)	$ 5.88	$ (1.50)			
	$ 5.84	$ (1.50)			

Net income (loss) per limited partner common units diluted (3)										
Weighted average limited partner common units basic (3)		10,131,928		10,071,970						
Weighted average limited partner common units diluted (3)		10,195,566		10,071,970						
Distributions declared per common and subordinated units	$	1.7400	$	0.2825						
Adjusted EBITDA (4):	$	105,266	$	76,158	$	49,781	$	64,398	$	53,286

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	Years Ended December 31, 2014	2013	2012 Predecessor	2011 Predecessor	2010 Predecessor
	(in thousands, except unit data and operating data)				
Cash Flow Data:					
Net cash (used in) provided by:					
Operating activities	$ 15,564	$ (80,663)	$ 163,129	$ (43,861)	$ 24,997
Investing activities	(132,492)	(46,751)	(79,693)	(17,004)	(9,387)
Financing activities	118,390	125,959	(111,560)	88,882	(17,162)
Other Financial and Operating Data (unaudited):					
Capital expenditures (5)	$ 18,580	$ 28,090	$ 7,293	$ 7,255	$ 9,587
Normal heating degree days (6)	6,749	6,752	6,787	6,752	6,752
Actual heating degree days. (6)	6,855	6,624	5,803	6,284	6,117
Variance from normal heating degree days	1.6%	(1.9)%	(14.5)%	(6.9)%	(9.4)%
Variance from prior period actual heating degree days	3.5%	14.1%	(7.7)%	2.7%	-11.5%
Total refined products volumes sold (barrels)	39,720	35,050	29,806	29,684	29,797
Variance from refined products volume from prior period	13.3%	17.6%	0.4%	(0.4)%	1.7%
Total natural gas volumes sold (MMBtus)	54,430	51,979	49,417	50,741	52,012
Variance from natural gas volume from prior period	4.7%	5.2%	(2.6)%	(2.4)%	2.2%
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 4,080	$ 2,046	$ 3,691	$ 31,829	$ 3,854
Property, plant and equipment, net	250,126	198,476	177,080	110,743	103,461
Total assets	1,339,840	1,090,241	1,054,247	970,050	867,995
Total debt (including capital lease obligations)	822,307	576,385	555,619	524,377	408,304
Total liabilities	1,223,946	1,018,948	913,041	791,649	697,811
Total unitholders /member s stockholder s equity	115,894	71,293	141,206	178,401	170,184

(1) During the year ended December 31, 2012, we delayed the timing of the Partnership s public offering and, as a result, deferred offering costs of $8.9 million were charged against earnings.

(2) Prior to the completion of the IPO, Sprague Energy Corp., which was converted into a limited liability company and renamed Sprague Operating Resource LLC on November 7, 2011, prepared its income tax provision as if it

had filed a consolidated U.S. federal income tax return and state tax returns as required. Commencing with the closing of the IPO, the Partnership is treated as pass through entity for U.S. federal income tax purposes. For pass through entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in our financial statements. The Partnership s Canadian entities are subject to Canadian income tax.

(3) Calculated based on operations since October 30, 2013, the date of the closing of the IPO. See Note 22 to the Consolidated and Combined Financial Statements included elsewhere in this report for the net income(loss) per limited partner unit calculation.

(4) For a discussion of the non-GAAP financial measure adjusted EBITDA, please read EDITDA and Adjusted EBITDA below.

(5) Includes approximately $8.3 million, $7.7 million, $6.0 million, $5.7 million and $8.1 million of maintenance capital expenditures for the years ended December 31, 2014, 2013, 2012, 2011 and 2010. Maintenance capital expenditures are capital expenditures made to replace assets or to maintain the long-term operating capacity of our assets or operating income.

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

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EDITDA and Adjusted EBITDA

We present the non-GAAP financial measures EBITDA and adjusted EBITDA in this Annual Report. We define EBITDA as net income(loss) before interest, income taxes, depreciation and amortization. We define adjusted EBITDA as EBITDA increased by unrealized hedging losses and decreased by unrealized hedging gains, in each case with respect to refined products and natural gas inventory and natural gas transportation contracts, decreased by gains on acquisition of business, increased by the write-off of deferred offering costs and adjusted for the net impact of bio-fuel excise tax credits in 2013/2012. Adjusted EBITDA is used as a supplemental financial measure by our management, and 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 cash sufficient 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.

For a discussion of how our management uses adjusted EBITDA, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations How Management Evaluates Our results of Operations Adjusted Gross Margin and Adjusted EBITDA.

The GAAP measure most directly comparable to EBITDA and adjusted EBITDA is net income (loss). The non-GAAP financial measures of EBITDA and adjusted EBITDA should not be considered as an alternative to net income (loss), 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. You should not consider EBITDA or adjusted EBITDA 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 we use capital assets, depreciation and amortization expense is a necessary element of our costs and ability to generate profits. Therefore, any measure that excludes depreciation and amortization expense may have material limitations;

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

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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.

The following table presents a reconciliation of EBITDA and adjusted EBITDA to net income (loss), the most directly comparable GAAP financial measure, on a historical basis, as applicable, for each of the years indicated:

	Years Ended December 31,				
	2014	2013	2012 Predecessor	2011 Predecessor	2010 Predecessor
			(in thousands)		
Reconciliation of EBITDA to net income (loss):					
Net (loss) income	$ 122,814	$ (29,838)	$ (12,831)	$ 29,572	$ 15,721
Add/(deduct):					
Interest expense, net	29,082	30,310	23,426	23,294	21,394
Tax expense (benefit)	5,509	4,259	(2,796)	16,636	10,288
Depreciation and amortization	17,625	16,515	11,665	10,140	10,531
EBITDA	$ 175,030	$ 21,246	$ 19,464	$ 79,642	$ 57,934
Add: unrealized (gain) loss on inventory (1)	(11,070)	4,188	227	(8,252)	(4,382)
Add: unrealized (gain) loss on natural gas transportation contracts (2)	(58,694)	55,745	17,650	(976)	(266)
Add/(deduct):					
Gain on acquisition of business (3)			(1,512)	(6,016)	
Write-off of deferred offering costs (4)			8,931		
Bio-fuel excise tax credits (5)		(5,021)	5,021		
Adjusted EBITDA	$ 105,266	$ 76,158	$ 49,781	$ 64,398	$ 53,286

(1) Inventory is valued at the lower of cost or market. The fair value of the derivatives the Company 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 (loss) income.

(2) The unrealized hedging (gain) loss on natural gas transportation contracts represents the Company s 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.

(3) Represents non-cash gains associated with (i) the re-measurement to fair value of our predecessor s 50% interest in Kildair in connection with its acquisition of the remaining 50% interest therein in 2012 and, (ii) the acquisition of an oil terminal at below fair value in 2011.

(4) During the year ended December 31, 2012, we delayed the filing of the IPO and, as a result, deferred offering costs of $8.9 million were charged against earnings. Please see Note 20 to our Consolidated and Combined

Financial Statements.

(5) On January 2, 2013, the U.S. federal government enacted legislation that reinstated an excise tax credit program available for certain of our bio-fuel blending activities. This program had previously expired on December 31, 2011 and was reinstated retroactively to January 1, 2012. During the year ended December 31, 2013, we recorded U.S. federal excise tax credits of $5.0 million related to our bio-fuel blending activities that had occurred during the year ended December 31, 2012. These credits have been recorded as a reduction of cost of products sold and, therefore, resulted in an increase in adjusted gross margin for the year ended December 31, 2013. This adjustment reflects the effect on our adjusted EBITDA had these credits been recorded in the period in which the blending activity took place.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

On October 30, 2013, we completed an initial public offering of 8,500,000 common units, representing a 42.2% limited partnership interest in us, at an initial public offering price of $18.00 per unit. Total proceeds of the sale of the common units were $140.3 million after deducting underwriting discounts and commissions, the structuring fee and offering expenses.

On December 9, 2014, the Partnership acquired all of the equity interests in Kildair through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties LLC. As this transaction represented a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson, which commenced on October 1, 2012.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Consolidated and Combined Financial Statements and notes to the Consolidated and Combined Financial Statements included elsewhere in this report, as well as the other financial information appearing elsewhere in this Annual Report.

EBITDA and Adjusted EBITDA are non-GAAP financial measures of performance that have limitations and should not be considered as a substitute for net income (loss) or cash provided by (used in) operating activities. Please see Item 6 above for a discussion of our use of EBITDA and Adjusted EBITDA and a reconciliation to net income (loss) for the periods presented.

Cautionary Statements Concerning Forward-Looking Statements

This Annual Report, including without limitation, our discussion and analysis of our financial condition and results of operations, and any information incorporated by reference, contains statements that we believe are forward-looking statements . Forward-looking statements give our current expectations and contain projections of results of operations or of financial condition, or forecasts of future events. Words such as may , assume , forecast , position , predict , strategy , expect , intend , plan , estimate , anticipate , believe , project , budget , potential , or continu expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors included in Part I, Item 1A Risk Factors of this Annual Report as well as the following risks and uncertainties:

- We may not have sufficient distributable cash flow following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.

- Our business could be affected by a range of issues, such as dramatic changes in commodity prices, energy conservation, competition, the global economic climate, movement of products between foreign locales and the United States, changes in local, domestic and worldwide inventory levels, seasonality and supply, weather and logistics disruptions.

A significant decrease in demand for the products and services we sell could reduce our ability to make distributions to our unitholders.

Increases and/or decreases in the prices of the products we sell could adversely impact the amount of borrowing available for working capital under our credit agreement.

Our results of operations are affected by the overall forward market for the products we sell.

Our business is seasonal and generally our financial results are lower in the second and third quarters of the calendar year, which may result in our need to borrow money in order to make quarterly distributions to our unitholders during these quarters. Warmer weather conditions could adversely affect our heating oil and residual oil sales.

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Our risk management policies cannot eliminate all commodity risk. In addition, noncompliance with our risk management policies could result in significant financial losses.

Nonperformance by our customers, suppliers and counterparties could result in losses to us.

We are exposed to trade credit risk in the ordinary course of our business as well as risks associated with our trade credit support in the ordinary course of business.

Competition from alternative energy sources, energy efficiency and new technologies could result in loss of some of our customers or reduction in demand for our products and services.

Certain of our contracts must be renegotiated or replaced periodically and our results of operations may be affected if we are unable to renegotiate or replace such contracts.

Adverse developments in the geographic areas in which we operate could affect our results of operations.

Compliance with changes to both federal and state environmental and non-environmental regulations could have a material adverse effect on our businesses.

Any disruptions in our labor force could affect our business.

A serious disruption to our information technology systems could significantly limit our ability to manage and operate our business efficiently.

Any failure to develop or maintain adequate internal controls over financial reporting may affect our results of operation.

Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of unitholders.

Unitholders have limited voting rights and, even if they are dissatisfied, cannot initially remove our general partner without its consent.

A significant increase in interest rates could adversely affect our ability to service our indebtedness.

The condition of credit markets may adversely affect us.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the IRS were to treat us as a corporation for U.S. federal income tax purposes, our distributable cash flow would be substantially reduced.

Our unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

The risk factors and other factors noted throughout this Annual Report could cause our actual results to differ materially from those contained in any forward-looking statement, and you are cautioned not to place undue reliance on any forward-looking statements.

Forward-looking statements speak only as of the date of this Annual Report (or other date as specified in this Annual 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 or review any forward-looking statements to reflect events or circumstances after the date of such statements.

A reference to a Note herein refers to the accompanying Notes to Consolidated and Combined Financial Statements contained in Part IV, Item 15. Exhibits and Financial Statement Schedules of this Annual Report.

Overview

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our general partner to engage in the purchase, storage, distribution and sale of refined products and natural gas, and to provide storage and handling services for a broad range of materials. We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own, operate and/or control a network of 19 refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of approximately 14.1 million barrels for refined products and other liquid materials, as well as approximately 1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 2.3 million barrels of additional storage capacity attributable to 47 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to more than 60 third-party terminals in the Northeast United States through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

We operate under four business segments: refined products, natural gas, materials handling and other operations. We evaluate the performance of our segments using adjusted gross margin, which is a non-GAAP financial measure used by management and external users of our Consolidated and Combined Financial Statements to assess the economic results of operations. For a description of how we define adjusted gross margin, see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Adjusted Gross Margin and Adjusted EBITDA. For a reconciliation of adjusted gross margin to the GAAP measure most directly comparable thereto, see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations.

On October 1, 2012, our Predecessor acquired control of Kildair, a Canadian distributor of residual fuel oil and asphalt and a commercial trucking business, by purchasing the remaining 50% equity interest. Prior to October 1, 2012, the results of operations of Kildair were recorded as equity in earnings of foreign affiliate. From October 1, 2012 and through the date of our IPO on October 30, 2013, the assets, liabilities and results of operations of Kildair have been consolidated into our financial statements, including our adjusted gross margin. Kildair was not part of our net assets following the completion of the IPO. On December 9, 2014, the Partnership acquired all of the equity interest in Kildair through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties, LLC. As this transaction represents a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson. We record Kildair s residual fuel oil and asphalt business in our refined products segment and their commercial trucking business in our other operations segment.

Our 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 our customers. We have wholesale customers who resell the refined products we sell to them and commercial customers who consume the refined products we sell to them. Our wholesale customers consist of more than 1,100 heating oil retailers and diesel fuel and gasoline resellers. Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, hospitals, educational institutions and asphalt paving companies. For the years ended December 31, 2014 and 2013, we sold approximately 1.7 billion and 1.5 billion gallons of refined products, respectively. For the years ended December 31, 2014 and 2013, our refined products segment accounted for 60% and 61% of our adjusted gross margin, respectively.

We also purchase, sell and distribute natural gas to more than 15,000 commercial and industrial customer locations across 13 states in the Northeast and Mid-Atlantic United States. We purchase the natural gas we sell from natural gas producers and trading companies. For the years ended December 31, 2014 and 2013, we sold 54.4 Bcf and 52.0 Bcf of natural gas, respectively. For the years ended December 31, 2014 and 2013, our natural gas segment accounted for 23% and 21% of our adjusted gross margin, respectively.

Our materials handling business is a fee-based business and is generally conducted under multi-year agreements. We offload, store and/or prepare for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, coal, petroleum coke, crude oil, caustic soda, tallow, pulp and heavy equipment. For the year ended December 31, 2014, we offloaded, stored and/or prepared for delivery 2.7 million short tons of products and 309.8 million gallons of liquid materials. For the year ended December 31, 2013, we offloaded, stored and/or prepared for delivery 2.1 million short tons of products and 246.7 million gallons of liquid materials. For the years ended December 31, 2014 and 2013, our materials handling segment accounted for 15% of our adjusted gross margin for both periods.

Our other operations segment includes the marketing and distribution of coal conducted in our Portland, Maine terminal and commercial trucking. For the years ended December 31, 2014 and 2013, our other operations segment accounted for approximately 2% and 3% of our adjusted gross margin, respectively.

We take title to the products we sell in our refined products, natural gas and other operations segments. We do not take title to any of the products in our materials handling segment. 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.

Non-GAAP Financial Measures

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

For a description of how we define EBITDA, and adjusted EBITDA see Part I, Item 6 Selected Financial Data above . A reconciliation of EBITDA and adjusted EBITDA is presented on page 41. For a description of how we define adjusted gross margin see below. A reconciliation of adjusted gross margin is presented on page 50.

How Management Evaluates Our Results of Operations

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

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. Commencing on October 30, 2013, 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. Operating expenses have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson

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. Commencing on October 30, 2013, 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. We believe that our SG&A expenses will increase as a result of our becoming a publicly traded partnership. SG&A expenses have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel

Johnson

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

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

EBITDA

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

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

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

Adjusted Gross Margin and Adjusted EBITDA

Management utilizes adjusted gross margin and adjusted EBITDA to assist it in reviewing our financial results and managing our business segments. 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 and natural gas transportation contracts. We define adjusted EBITDA as EBITDA increased by unrealized hedging losses and decreased by unrealized hedging gains, in each case with respect to refined products and natural gas inventory and natural gas transportation contracts, decreased by gains on acquisition of businesses, increased by the write-off of deferred offering costs and adjusted for the net impact of bio-fuel excise tax credits. Management believes that adjusted gross margin and adjusted EBITDA provide information that reflects our market or economic performance. We trade, purchase and sell energy commodities with market values that are constantly changing, which makes it important for management to evaluate our performance, as well as our physical and derivative positions, on a daily basis. Management reviews the daily operational performance of our supply activities, as well as our monthly financial results, on an adjusted gross margin and adjusted EBITDA basis. Adjusted gross margin and adjusted EBITDA have no impact on reported volumes or net sales.

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

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

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

Hedging Activities

We economically hedge our inventory within the guidelines set in our risk management policy. In a rising commodity price environment, the market value of our inventory will generally be higher than the cost of our inventory. For GAAP purposes, we are required to value our inventory at the lower of cost or market, or LCM. The hedges on this inventory will lose value as the value of the underlying commodity rises, creating hedging losses. Because we do not utilize hedge accounting, GAAP requires us to record those hedging losses in our statement of operations. In contrast, in a declining commodity price market we generally incur hedging gains. GAAP requires us to record those hedging gains in our statement of operations. The refined products inventory market valuation is calculated daily using independent bulk market price assessments from major pricing services (either Platts or Argus). These third-party price assessments are primarily based in New York Harbor, or NYH, with our inventory values determined after adjusting the NYH prices to the various inventory locations by adding expected cost differentials (primarily freight) compared to a NYH supply source. 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 economically 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 increase. If the market value of the transportation asset exceeds costs, we can 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). As the value of the natural gas transportation assets increase, the hedges on the natural gas transportation assets lose value, creating hedging losses in our statement of operations. The natural gas transportation assets market value is calculated daily based on the volume and prices at the corresponding pipeline locations. The daily prices are based on trader assessed quotes which represent observable transactions in the market place, with the end-month valuations primarily based on Platts prices where available or adding a location differential to the price assessment of a more liquid location.

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

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Recent Trends and Outlook

This section identifies certain trends and outlook that may affect our financial performance and results of operations in the future. Our economic and industry-wide trends and outlook include the following:

New, stricter environmental laws and regulations are increasing the compliance cost of terminal operations, which could adversely affect our results of operations and financial condition. Our operations are subject to federal, state and local laws and regulations regulating product quality specifications and other environmental matters. The trend in environmental regulation is towards more restrictions and limitations on activities that may affect the environment. We try to anticipate future regulatory requirements that might be imposed and to plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. However, there can be no assurances as to the timing and type of such changes in existing laws or the promulgation of new laws or the amount of any required expenditures associated therewith.

Dodd-Frank regulations could increase costs associated with hedging our commodity exposure. We employ derivatives of the types subject to regulation as part of the Dodd Frank Act. We, along with all participants in commodity markets, may face increased margin requirements on the derivatives we employ to hedge our commodity exposure, which would reduce capital available for other purposes.

Consolidation of the Northeast terminal market. In recent years, major U.S. oil companies have disposed of various terminal assets in the Northeast and reduced their participation in wholesale marketing in the region. The key terminals remain in operation as an integral part of the supply chain, though they are generally controlled by other industry participants.

Growth in exploration and production of shale gas has contributed to a relative weakness of domestic natural gas prices compared to competitive refined products in the *Northeast United States,* ***leading to expanded use of natural gas in our marketing area.*** Natural gas usage in the Northeast United States has grown substantially, as the supplies of gas from shale formations have grown both in the region (*e.g.*, Marcellus Shale) and the other parts of the United States. Further expansion of domestic natural gas supplies is expected, with consumption in the Northeast United States also expected to grow as infrastructure developments continue. Moreover, the growth in Marcellus Shale production continues to increase the availability of natural gas in our operating areas. This development is expected to decrease the need for traditional, long-distance sourcing of natural gas supplies using interstate pipeline capacity and natural gas storage capacity. In addition, the potential natural gas supply counterparties in our operating areas are expanding, and there are now some relatively short-term arrangements and additional hedging opportunities available in the Northeast United States.

The recent trend of declining refining products prices could positively impact performance. Refined product prices declined sharply during 2014 (e.g., prompt month NYMEX ULSD futures closing price was 40% lower at the end of 2014 compared to the end of 2013). If the refined products price environment remains lower, this could help promote additional product demand as customers would be generally less prone to engage in conservation efforts. Credit risk would also be reduced as a lower level of credit would be necessary to meet customer requirements. In addition, working capital costs would also be decreased, as the costs to hold inventory and finance accounts receivable would both be reduced with lower prices.

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Factors that Impact our Business

Our results of operations and financial condition, as well as those of our competitors, will depend in part upon certain economic or industry-wide factors, including the following:

Seasonality and weather conditions. Our financial results are impacted by seasonality in our businesses and are generally better during the winter months, primarily because a material part of our business consists of supplying heating oil, residual fuel oil and natural gas for space heating purposes during the winter. For example, over the 36-month period ended December 31, 2014, we generated an average of approximately 71% of our total heating oil and residual fuel oil net sales during the months of November through March in the Northeast United States. In addition, weather conditions, particularly during these five months, have a significant impact on the demand for our products. Warmer-than-normal temperatures during these months in our areas of operations can decrease the total volume of heating oil, residual fuel oil and natural gas we sell and the adjusted gross margins realized on those sales, whereas colder-than-normal temperatures increase demand for those products and the associated adjusted gross margins.

***The impact of the market structure on our hedging strategy*.** We typically hedge our exposure to commodity price moves with NYMEX futures contracts and OTC swaps. In markets where futures prices are higher than spot prices (typically referred to as contango), we generate positive margins when rolling our inventory hedges to successive months. In markets where futures prices are lower than spot prices (typically referred to as backwardation), we realize losses when rolling our inventory hedges to successive months. In backwardated markets, we operate with lower inventory levels and, as a result, have reduced hedging and financing requirements, thereby limiting losses.

***Energy efficiency, new technology and alternative fuels could reduce demand for our products*.** Increased conservation and technological advances have adversely affected the demand for heating oil and residual fuel oil. Consumption of residual fuel oil, in particular, has steadily declined in recent years, primarily due to customers converting from other fuels to natural gas, weak industrial demand and tightening of environmental regulations. Use of natural gas is expected to continue to displace other fuels, which we believe will favorably impact our natural gas volumes and margins.

***Absolute price increases can lead to reduced demand, increased credit risk, higher interest costs and temporarily reduced margins*.** As refined product prices rise, we generally experience reduced demand as customers engage in conservation efforts. We also experience a higher level of credit risk from our customers. In addition, our working capital requirements for holding inventory and financing receivables increase with higher price levels, while adjusted gross margin levels may stay relatively constant for a period of time due to competitive pressures.

Interest rates could rise. Since mid-2009, the credit markets have been experiencing near-record lows in interest rates. As the overall economy strengthens, it is expected that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. This could affect our ability to access the debt capital markets to the extent we may need, in the future, to fund our growth. In addition, interest rates could be higher than current levels, causing our financing costs to increase accordingly. During the 24 months ended December 31, 2014, we hedged approximately 36% of our floating-rate debt with fixed-for-floating interest rate swaps. Although higher interest rates could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, reduce debt or for other purposes.

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Results of Operations

The following table presents our volume, net sales and adjusted gross margin by segment, as well as our adjusted EBITDA and information on weather conditions, for the years ended December 31, 2014, 2013 and 2012.

Our acquisition of Kildair on December 9, 2014 represents a transfer of entities under common control. The information presented herein has been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson, which commenced on October 1, 2012.

	Years Ended December 31,		
	2014	2013	2012 Predecessor
	($ and volumes in thousands)		
Volumes:			
Refined products (gallons)	1,668,240	1,472,100	1,251,852
Natural gas (MMBtus)	54,430	51,979	49,417
Materials handling (short tons)	2,663	2,145	2,595
Materials handling (gallons)	309,834	246,708	248,514
Net Sales:			
Refined products	$ 4,650,871	$ 4,331,410	$ 3,757,859
Natural gas	359,984	304,843	242,006
Materials handling	37,776	28,446	32,536
Other operations	21,131	18,650	11,506
Total net sales	$ 5,069,762	$ 4,683,349	$ 4,043,907
Adjusted Gross Margin:			
Refined products	$ 146,021	$ 114,744	$ 77,480
Natural gas	55,536	40,373	26,844
Materials handling	37,811	28,430	32,320
Other operations	5,599	5,547	2,788
Total adjusted gross margin	$ 244,967	$ 189,094	$ 139,432
Reconciliation to Operating Income:			
Total adjusted gross margin	$ 244,967	$ 189,094	$ 139,432
Add: unrealized gain (loss) on inventory (1)	11,070	(4,188)	(227)
Add: unrealized gain (loss) on natural gas transportation contracts (2)	58,694	(55,745)	(17,650)
Operating expenses	(62,993)	(53,273)	(47,054)
Selling, general and administrative	(76,420)	(55,210)	(46,449)
Write-off of deferred offering costs (3)			(8,931)
Depreciation and amortization	(17,625)	(16,515)	(11,665)
Operating income	157,693	4,163	7,456
Gain on acquisition of business			1,512

Other (expense) income	(288)	568	(160)
Interest income	569	604	534
Interest expense	(29,651)	(30,914)	(23,960)
Income tax (provision) benefit	(5,509)	(4,259)	2,796
Equity in net loss in foreign affiliate			(1,009)
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)
Other Data:			
Adjusted EBITDA (4)	$ 105,266	$ 76,158	$ 49,781
Normal heating degree days (5)	6,749	6,752	6,787
Actual heating degree days	6,855	6,624	5,803
Variance from normal heating degree days	1.6%	(1.9)%	(14.5)%
Variance from prior period actual heating degree days	3.5%	14.1%	(7.7)%

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(1) Inventory is valued at the lower of cost or market. The fair value of the derivatives we use to economically hedge our inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging losses (gains) with respect to the derivatives that are included in net income (loss).
(2) The unrealized (gain) loss on natural gas transportation contracts represents our estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net (loss) income until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts are executory contracts that do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging losses (gains) in net (loss) income.
(3) During the year ended December 31, 2012, we delayed the timing of our public offering and as a result, deferred offering costs of $8.9 million were charged against earnings.
(4) For a discussion of the non-GAAP financial measure adjusted EBITDA, please read EDITDA and Adjusted EBITDA beginning on page 40.
(5) As reported by the NOAA/National Weather Service for the New England oil home heating region over the period of 1981-2011.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Our results of operations for the year ended December 31, 2014 reflect increasing sales volume, net sales and adjusted unit gross margin in our refined products segment, increasing volume, net sales and adjusted unit gross margin in our natural gas segment and increasing volumes, net sales and adjusted gross margin in our materials handling segment.

Adjusted gross margin for the year ended December 31, 2014 reflects increasing adjusted gross margin for refined products and natural gas.

	Years Ended December 31,		Increase/(Decrease)	
	2014	2013	$	%
	($ in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,668,240	1,472,100	196,140	13%
Natural gas (MMBtus)	54,430	51,979	2,451	5%
Materials handling (short tons)	2,663	2,145	518	24%
Materials handling (gallons)	309,834	246,708	63,126	26%
Net Sales:				
Refined products	$ 4,650,871	$ 4,331,410	$ 319,461	7%
Natural gas	359,984	304,843	55,141	18%
Materials handling	37,776	28,446	9,330	33%
Other operations	21,131	18,650	2,481	13%
Total net sales	$ 5,069,762	$ 4,683,349	$ 386,413	8%
Adjusted Gross Margin:				
Refined products	$ 146,021	$ 114,744	$ 31,277	27%
Natural gas	55,536	40,373	15,163	38%

Materials handling	37,811	28,430	9,381	33%
Other operations	5,599	5,547	52	1%
Total adjusted gross margin	$ 244,967	$ 189,094	$ 55,873	30%
Adjusted Unit Gross Margin:				
Refined products	$ 0.088	$ 0.078	$ 0.010	13%
Natural gas	$ 1.020	$ 0.777	$ 0.243	31%

Refined Products

Refined products net sales were $4.7 billion and $4.3 billion for the years ended December 31, 2014 and 2013, respectively. Refined products net sales increased $319.5 million, or 7%, which was driven primarily by higher refined products sales volumes. Refined products sales volumes were 1.7 billion gallons and 1.5 billion gallons for the years ended December 31, 2014 and 2013, respectively. Distillate sales volumes increased 186.6 million gallons, or 20%, period over period, with substantial increases in both diesel and heating oil. The largest volume increases were in diesel fuel due to the contracts acquired from Hess Corporation at the end of 2013 and higher sales to power plant customers to meet power generation requirements as the colder weather conditions in the first quarter led to natural gas curtailments. Heating oil volumes were also up sharply, driven by sustained colder weather conditions during the winter and increased share in key markets due to enhanced asset positions, including the Bridgeport, Connecticut terminal that was purchased in the second half of 2013. The purchase of Castle in early December 2014 also contributed to the distillate volume gains.

Gasoline sales volumes increased by approximately 2.0 million gallons, or 1%, period over period. Residual fuel oil and asphalt sales volumes increased 7.5 million gallons, or 2%, period over period, with the volume increases a result of natural gas curtailments primarily due to the colder weather. The average refined products selling price per gallon was 5% lower for the year ended December 31, 2014 as compared to the same period in 2013, with a significant decline in the fourth quarter offsetting the higher prices earlier in the year driven by declining world crude oil prices.

Refined products adjusted gross margin, was $146.0 million and $114.7 million for the years ended December 31, 2014 and 2013, respectively. The refined products adjusted gross margin increase of $31.3 million, or 27%, was driven by improved returns in distillate fuels, with both heating oil and diesel fuel providing substantial increases. The increase in heating oil adjusted gross margin was due to a combination of higher volumes and unit margins. The improvement in diesel margin generation was largely due to higher volumes, though unit margins also improved. The additional volumes included increases from sales to the former Hess Corporation customers as well as the incremental power generation requirements resulting from natural gas curtailments. Gasoline volumes improved modestly and margins increased as well, supported by proceeds from the sale of RINs and higher gasoline throughput revenues compared to the previous year. Higher residual fuel sales volumes and improved unit margins led to the increase in adjusted gross margin for heavy fuel oil.

In January 2013 a previously expired bio-fuel excise tax credit was retroactively reinstated to include all applicable 2012 activity. As a result, the refined products adjusted gross margin results for the year ended December 31, 2013 includes a $5.0 million benefit. There was no comparable adjustment for the year ended December 31, 2014.

Natural Gas

Natural gas net sales were $360.0 million and $304.8 million for the years ended December 31, 2014 and 2013, respectively. The natural gas sales increase of $55.2 million, or 18%, was driven by higher commodity prices as the average natural gas price per MMBtu was approximately 13% higher during the year ended December 31, 2014 as compared to the same period in 2013. The stronger natural gas price environment was due in part to the higher demand driven by colder weather during 2014, in particular during the first quarter. Natural gas sales volumes increased by nearly 5% for the year due primarily to a combination of strong sales volumes in the first quarter due to colder weather and the addition of the Metromedia volumes at the beginning of the fourth quarter.

Natural gas adjusted gross margin was $55.5 million and $40.4 million for the years ended December 31, 2014 and 2013, respectively. In addition to adjusted gross margin generated from the inclusion of Metromedia sales beginning in the fourth quarter, the natural gas adjusted gross margin increase of $15.1 million, or 38%, was due primarily to higher demand supported by colder weather conditions during the first quarter, the continuing transition of our customer base towards smaller commercial and industrial end users with higher unit margins, and additional margin generation from optimization of transportation assets and storage utilization, particularly during volatile pricing periods. In connection with the acquisition of Metromedia Energy we recorded an asset of $39.4 million and a liability of $1.5 million, representing the fair value of natural gas transportation contracts acquired which will be amortized into cost of products sold over the life of the underlying agreements. During the year ended December 31, 2014, we recorded a charge to cost of products sold of $21.9 million which included $13.6 million due to a decline in value as a result of decreasing natural gas spreads.

Materials Handling

Materials handling net sales were $37.8 million and $28.4 million for the years ended December 31, 2014 and 2013, respectively. The materials handling net sales increase of $9.4 million, or 33%, was primarily due to the start-up of the crude handling project at Kildair which increased liquids handling revenue substantially, and an increase in dry bulk handling volumes at other Sprague facilities.

The materials handling adjusted gross margin increase of $9.4 million, or 33%, was primarily due to the initiation of Kildair s crude handling activities and an increase in dry bulk handling volumes of salt, petroleum coke, and gypsum. The dry bulk increase was driven by a combination of low activity in 2013 due to higher bulk product inventories as a result of warm weather (e.g., salt) and timing differences in deliveries (i.e., a shipment in early 2014 versus late 2013). Some other gains such as improved break bulk returns, particularly for newsprint, also contributed to the overall margin increase in 2014.

Other Operations

Sales from our other operations were $21.1 million and $18.7 million for the years ended December 31, 2014 and 2013, respectively, representing an increase of $2.4 million. This was primarily due to increased sales of coal partially offset by a decrease in commercial trucking activities of Kildair.

Adjusted gross margin from our other operations remain relatively unchanged at $5.6 million for the year ended December 31, 2014, as compared to $5.5 million for the year ended December 31, 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Our results of operations for the year ended December 31, 2013 reflect increasing sales volume, net sales and adjusted unit gross margin in our refined products segment, increasing volume, net sales and adjusted unit gross margin in our natural gas segment and decreasing volumes, net sales and adjusted gross margin in our materials handling segment.

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Adjusted gross margin for the year ended December 31, 2013 reflects increasing adjusted gross margin for refined products and natural gas.

	Years Ended December 31, 2013	2012 Predecessor	Increase/(Decrease) $	%
	($ in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,472,100	1,251,852	220,248	18%
Natural gas (MMBtus)	51,979	49,417	2,562	5%
Materials handling (short tons)	2,145	2,595	(450)	(17)%
Materials handling (gallons)	246,708	248,514	(1,806)	(1)%
Net Sales:				
Refined products	$ 4,331,410	$ 3,757,859	$ 573,551	15%
Natural gas	304,843	242,006	62,837	26%
Materials handling	28,446	32,536	(4,090)	(13)%
Other operations	18,650	11,506	7,144	62%
Total net sales	$ 4,683,349	$ 4,043,907	$ 639,442	16%
Adjusted Gross Margin:				
Refined products	$ 114,744	$ 77,480	$ 37,264	48%
Natural gas	40,373	26,844	13,529	50%
Materials handling	28,430	32,320	(3,890)	(12)%
Other operations	5,547	2,788	2,759	99%
Total adjusted gross margin	$ 189,094	$ 139,432	$ 49,662	36%
Adjusted Unit Gross Margin:				
Refined products	$ 0.078	$ 0.062	$ 0.016	26%
Natural gas	$ 0.777	$ 0.543	$ 0.234	43%

Refined Products

Refined products net sales were $4.3 billion and $3.8 billion for the years ended December 31, 2013 and 2012, respectively. Refined products net sales increased $573.6 million, or 15%, which was driven primarily by higher refined products sales volumes. Refined products sales volumes were 1.5 billion gallons and 1.3 billion gallons for the years ended December 31, 2013 and 2012, respectively. Distillate sales volumes increased 118.2 million gallons, or 14%, period over period, with higher volumes in all four quarters during 2013. The percentage increases were highest in the three months ending March 31, 2013 compared to the same period in 2012, with a key factor being the unseasonably warm weather during that time period in 2012. Gasoline sales volumes decreased by approximately 32.1 million gallons, or 12%, for the year ended December 31, 2013 as compared to the same period in 2012. This decrease occurred primarily due to aggressive pricing by our competitors. Residual fuel oil and asphalt sales volumes increased 134.2 million gallons, or 77%, for the year ended December 31, 2013 as compared to the same period in 2012. Of this increase, approximately 130.6 million gallons was due to Kildair, which was acquired on October 1, 2012. The average refined products selling price per gallon was 2% lower for the year ended December 31, 2013 as compared to the same period in 2012.

Refined products adjusted gross margin, was $114.7 million and $77.5 million for the years ended December 31, 2013 and 2012, respectively. Refined products adjusted gross margin increased $37.2 million, or 48%. Of this increase, approximately $23.3 million was due to Kildair, which was acquired on October 1, 2012. In addition to Kildair, returns in distillates improved, in particular heating oil. Heating oil volumes and unit margins both improved substantially, partly due to the colder weather conditions in 2013. The reinstatement of the U.S. federal bio-fuel excise tax credits in January 2013 contributed $5.0 million to the increase.

Natural Gas

Natural gas net sales were $304.8 million and $242.0 million for the years ended December 31, 2013 and 2012, respectively. The natural gas sales increase of $62.8 million, or 26%, was driven by higher commodity prices as the average natural gas marketing price per MMBtu was approximately 20% higher during the year ended December 31, 2013 as compared to the same period in 2012. The stronger natural gas price environment was due in part to the higher weather-driven demand during 2013. Natural gas sales volumes increased 5% for the year ended December 31, 2013 as compared to the same period in 2012, with the colder weather being a contributing factor.

Natural gas adjusted gross margin was $40.4 million and $26.8 million for the years ended December 31, 2013 and 2012, respectively. The natural gas adjusted gross margin increase of $13.5 million, or 50%, was due to a number of factors including higher sales volumes partly driven by the colder weather conditions, the continuing transition of our customer base towards smaller commercial and industrial end users, and additional margin generation due to optimization of transportation assets and storage utilization. The transportation/storage optimization opportunities were most notable during the volatile pricing periods observed during the winter months.

Materials Handling

Materials handling net sales were $28.4 million and $32.5 million for the years ended December 31, 2013 and 2012, respectively. The materials handling net sales decrease of $4.1 million, or 13%, was primarily due to a decrease in dry bulk activities including salt, gypsum and petcoke. In addition, windmill component handling activities were substantially lower in the year ended December 31, 2013 compared to the same period in 2012.

The materials handling adjusted gross margin decrease of $3.9 million, or 12%, was primarily due to a reduction in dry bulk activities including salt, gypsum, windmill component handling, and petcoke, generally reflecting the timing requirements of our customers. These decreases were partially offset by increased asphalt handling revenues over the same time periods due primarily to increased volumes by a major customer.

Other Operations

Sales from our other operations were $18.7 million and $11.5 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $7.1 million. Of this increase, approximately $7.8 million was due to the commercial trucking activities of Kildair, which was acquired on October 1, 2012.

Adjusted gross margins from our other operations were $5.5 million and $2.8 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $2.7 million. Of this increase, substantially all was due to the commercial trucking activities of Kildair, which was acquired on October 1, 2012.

Operating Costs and Expenses

Our acquisition of Kildair on December 9, 2014 represents a transfer of entities under common control. The information presented herein has been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson, which commenced on October 1, 2012.

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The following table presents our operating expenses and selling, general and administrative expenses for the years ended December 31, 2014, 2013, and 2012.

	Years Ended December 31,		
	2014	2013	2012 Predecessor
	($ in thousands)		
Operating expenses	62,993	53,273	47,054
Selling, general and administrative expenses	76,420	55,210	46,449
Write-off of deferred offering costs			8,931
Depreciation and amortization	17,625	16,515	11,665

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

	Years Ended December 31,		Increase/(Decrease)	
	2014	2013	$	%
	($ in thousands)			
Operating expenses	$ 62,993	$ 53,273	$ 9,720	18%
Selling, general and administrative expenses	$ 76,420	$ 55,210	$ 21,210	38%
Depreciation and amortization	$ 17,625	$ 16,515	$ 1,110	7%

Operating Expenses. Operating expenses for the year ended December 31, 2014 increased $9.7 million, or 18%, as to the year ended December 31, 2013. Of this increase, $3.8 million was due to increased maintenance, insurance and utility expenses, $2.7 million was due to increased dry bulk handling volumes, $2.4 million was due to terminal operating expenses related to our Bridgeport terminal which was acquired on July 31, 2013 and $0.6 million was due to terminal operating expenses related to our Bronx terminal which was acquired on December 8, 2014.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for the year ended December 31, 2014 increased $21.2 million, or 38%, as compared to the year ended December 31, 2013. Of this increase $12.6 million was due to higher employee related expenses primarily attributed to increased incentive compensation and sales commissions as a result of higher earnings performance, $3.3 million related to increased professional fees associated with public company reporting and compliance requirements, $2.8 million was related to expenses associated with mergers and acquisition activities, and $2.6 million was due to selling, general and administrative expenses related to the Metromedia Energy and Castle Oil acquisitions.

Depreciation and Amortization. Depreciation and amortization for the year ended December 31, 2014 increased $1.1 million, or 7%, as compared to the year ended December 31, 2013. This increase was predominantly driven by the amortization of intangible assets arising from the Metromedia Energy acquisition in the fourth quarter.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Years Ended December 31,		Increase/(Decrease)	
	2013	2012	$	%
	($ in thousands)			

Operating expenses	$ 53,273	$ 47,054	$ 6,219	13%
Selling, general and administrative expenses	$ 55,210	$ 46,449	$ 8,761	19%
Write-off of deferred offering costs	$	$ 8,931	$ (8,931)	*
Depreciation and amortization	$ 16,515	$ 11,665	$ 4,850	42%

* Not meaningful

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Operating Expenses. Operating expenses for the year ended December 31, 2013 increased $6.2 million, or 13%, as compared to the year ended December 31, 2012, primarily due to the inclusion of $10.2 million and $3.3 million of Kildair s operating expenses for the years ended December 31, 2013 and 2012, respectively, representing an increase of $6.9 million. The remaining operating expenses decrease of $0.7 million was driven by a decrease of $1.7 million due to lower costs associated with materials handling operations, offset by an increase of $1.2 million due to the operating expenses of our Bridgeport terminal, which was acquired on July 31, 2013.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for the year ended December 31, 2013 increased $8.8 million, or 19%, as compared to the year ended December 31, 2012. Selling, general and administrative expenses include Kildair s expenses of $5.9 million and $1.2 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $4.7 million. The remaining increase in selling, general and administrative expenses was primarily due to incentive compensation as a result of higher earnings performance.

Write-off of Deferred Offering Costs. During the year ended December 31, 2012, deferred offering costs of $8.9 million were charged against earnings due to an extended delay in the timing of our IPO. The total charge included $6.5 million of offering costs previously deferred as of December 31, 2011 and $2.4 million of deferred offering costs incurred during the year ended December 31, 2012.

Depreciation and Amortization. Depreciation and amortization for the year ended December 31, 2013 increased $4.9 million, or 42%, as compared to the year ended December 31, 2012. Kildair s depreciation and amortization expense was $6.9 million and $1.8 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $5.1 million.

Interest Expense, Net, Equity in Net Loss of Foreign Affiliate and Gain on Acquisition of Business

The following table presents our interest expense, net, equity in net loss of foreign affiliate and gain on acquisition of business for the years ended December 31, 2014, 2013, and 2012.

	Years Ended December 31,		
	2014	2013	2012 Predecessor
	($ in thousands)		
Interest expense, net	29,082	30,310	23,426
Equity in net loss of foreign affiliate			(1,009)
Gain on acquisition of business			1,512

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

	Years Ended December 31,		Increase/(Decrease)	
	2014	2013	$	%
	($ in thousands)			
Interest expense, net	$ 29,082	$ 30,310	$ (1,228)	(4)%

Interest Expense, net. Interest expense, net for the year ended December 31, 2014 decreased $1.2 million, or 4%, as compared to the year ended December 31, 2013. Of this decrease, $2.6 million was related to the expiration of interest rate swaps related to a portion of our variable rate debt obligations, offset by increased amortization of debt issuance costs associated with the Partnership s new credit facilities.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Years Ended December 31,		Increase/(Decrease)	
	2013	2012	$	%
	($ in thousands)			
Interest expense, net	$ 30,310	$ 23,426	$ 6,884	29%
Equity in net loss of foreign affiliate	$	$ (1,009)	$ 1,009	*
Gain on acquisition of business	$	$ 1,512	$ (1,512)	*

* Not meaningful

Interest Expense, net. Interest expense, net for the year ended December 31, 2013 increased $6.9 million, or 29%, as compared to the year ended December 31, 2012. Interest expense included Kildair s expenses of $5.3 million and $1.1 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $4.2 million. The remaining increase in interest expense of $2.7 million was primarily due to higher interest rate derivative obligations and increased amortization of debt issuance costs associated with the Partnership s new credit facility.

Equity in Net Loss of Foreign Affiliate. The equity in net loss of our Predecessor s foreign affiliate for the year ended December 31, 2012, was $1.0 million. For the year ended December 30, 2011 and through September 30, 2012, we recorded the activity of Kildair as an equity investment in a foreign affiliate. Kildair was fully consolidated by our Predecessor beginning on October 1, 2012.

Gain on Acquisition of Business. During the year ended December 31, 2012, we recognized a gain of $1.5 million as a result of re-measuring to fair value our 50% equity interest in Kildair before the business combination in which we acquired the remaining 50% of the equity interest in Kildair. The gain was calculated as the difference between the acquisition-date fair value ($57.0 million) and the book value immediately prior to the acquisition date ($55.5 million). The fair value was determined using valuation techniques including the discounted cash flow approach and the market multiple approach (enterprise value of earnings before interest, taxes, depreciation and amortization). The discounted cash flow approach incorporated assumptions including estimated future cash flows and a discount rate that reflects consideration of risk free rates as well as market risk and is a Level 3 measure.

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 the credit agreement and potential future issuances of additional partnership interests or debt securities are our primary sources of liquidity. At December 31, 2014, the Partnership had net working capital of approximately $201.8 million.

On December 9, 2014, we entered into an amended and restated credit agreement that matures on December 9, 2019 and consists of three revolving credit facilities: (1) $1.0 billion working capital facility, (2) $120.0 million multi-currency working capital facility and (3) a $400.0 million acquisition facility.

At December 31, 2014, under our working capital facilities, the Partnership had total outstanding borrowings of approximately $503.2 million and approximately $120.2 million of outstanding letters of credit. As of December 31, 2014, the working capital facility borrowing base was approximately $843.3 million, providing us with approximately $219.9 million in undrawn borrowing capacity. As of December 31, 2014, the Partnership had approximately $311.6 million in outstanding borrowings under our acquisition facility, providing us with approximately $88.4 million in undrawn borrowing capacity under the acquisition facility.

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, inventory is reduced, accounts receivable are collected and converted into cash and debt is paid down. During the twelve months ended December 31, 2014, the amount drawn under the working capital facility of our credit agreements fluctuated from a low of approximately $163.0 million to a high of approximately $503.2 million.

We believe that we will 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.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Capital Expenditures

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

During the year ended December 31, 2014, we spent a total of approximately $8.3 million for maintenance capital expenditures, of which $1.0 million was incurred by Kildair, and we spent $10.3 million for expansion and/or upgrades of our terminals, of which $8.8 million was incurred by Kildair primarily related to a crude storage and handling construction project. 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.

Contractual Obligations

We have contractual obligations that are required to be settled in cash. The amounts of our contractual obligations at December 31, 2014 were as follows:

		Payments due by period			
	Total	**Less than**	**1-3 years**	**4-5 years**	**More than 5 years**

		1 year			
			($ in thousands)		
Operating lease obligations (1)	$ 59,432	$ 14,224	$ 34,794	$ 3,962	$ 6,452
Capital lease obligations (including interest)	$ 8,441	$ 1,723	$ 3,899	$ 582	$ 2,237
Credit facilities (including interest) (2)	$ 904,085	$ 102,992	$ 199,838	$ 601,255	$ 0
Product purchases (3)	$ 820,090	$ 789,550	$ 30,540	$	$ 0
Transportation and storage (4)	$ 42,337	$ 18,971	$ 17,978	$ 5,388	$ 0
Total	$ 1,834,385	$ 927,460	$ 287,049	$ 611,187	$ 8,689

(1) We have leases for a refined products terminal, refined products storage, maritime charters, vehicles, office and plant facilities, computer and other equipment that are accounted for as operating leases.
(2) Amounts include principal and interest on our working capital revolving credit facility and our acquisition line revolving credit facility at December 31, 2014. The credit agreement has a contractual maturity of December 9, 2019 and no scheduled principal payments are required prior to that date. However, we repay amounts outstanding and borrow funds based on our working capital requirements. Therefore, the current portion of the working capital revolving credit facility included in our Consolidated Balance Sheets is the amount we expect to pay down during the course of the year, and the long-term portion of the working capital revolving credit facility is the amount we expect to be outstanding during the entire year. Interest is calculated using the rates in effect as of December 31, 2014, and we assume a ratable payment of the current portion of the working capital revolving credit facility through the expiration date.
(3) Product purchases include estimated purchase commitments for refined products and natural gas. The value of these future supply commitments, if not fixed in price, will fluctuate based on prevailing market prices. The prices at which we purchase refined products and natural gas are determined by reference to published market prices prevailing at the time of purchase. The value of our product purchase commitments were computed based on contractual prices.
(4) Transportation and storage commitments include refined products throughput agreements at third-party terminals and natural gas pipeline transportation and storage agreements that have minimum usage requirements.

Cash Flows

	Years Ended December 31,		
	2014	2013	2012 Predecessor
	($ in thousands)		
Net cash provided by (used in) operating activities	15,564	(80,663)	163,129
Net cash used in investing activities	(132,492)	(46,751)	(79,693)
Net cash provided by (used in) financing activities	118,390	125,959	(111,560)

Years Ended December 31, 2014, December 31, 2013 and December 31, 2012

Operating Activities

Net cash provided by operating activities for the year ended December 31, 2014 was approximately $15.6 million. Cash flows from operations were favorably impacted by net income of $122.8 million, as well as a decrease of $84.5 million in inventory, primarily related to lower commodity prices. Cash flows from operations were negatively impacted as a result of an increase of $242.6 million in derivative instruments resulting from the drop in commodity prices in refined products and natural gas during the last four months of the year and an increase of $19.1 million in accounts receivable due to a build-up of receivables in refined products and natural gas as a result of Sprague s acquisitions.

Net cash used in operating activities for the year ended December 31, 2013 was approximately $80.7 million. Cash flows from operations were negatively impacted by a reduction of cash flow of $158.2 million related to accounts receivable which primarily was the result of a $130.2 million distribution of accounts receivable to Sprague Holdings which occurred in connection with the public offering. These distributions of accounts receivable had a negative impact on cash flow from operations since they represented current year operating activity that was transferred prior to the point when cash was collected. Cash flows from operations were positively impacted by a reduction of $51.5 million in derivative instruments relating to less customer demand for locking in fixed price forward commitments and a decrease of $30.6 million in inventory, primarily related to the weak market structure in refined products coupled with significantly cold weather at the end of the year and strong sales from customer demand.

Net cash provided by operating activities for the year ended December 31, 2012 was approximately $163.1 million and was driven by a decrease of $54.4 million in inventory relating to a weak market structure in heating oil and residual fuel oil and warm weather conditions impacting customer demand, an increase of $32.5 million in accounts payable and accrued liabilities, primarily due to timing of invoice payments for product purchases, a decrease of $24.2 million in account receivable, and a decrease of $27.2 million in derivative instruments relating to lower customer demand for locking in fixed price forward commitments and was partially offset by a net loss of $12.8 million.

Investing Activities

Net cash used in investing activities for the year ended December 31, 2014 was approximately $132.5 million and consisted primarily of $115.5 million related to the net cash used to finance our acquisitions, $8.8 million related to expansion capital expenditures at Kildair for the crude oil storage and handling construction project, and $9.8 million relating to capital expenditure projects across our terminal system.

Net cash used in investing activities for the year ended December 31, 2013 was approximately $46.8 million and consisted primarily of $20.7 million related to the purchase of the Bridgeport terminal, $19.1 million related to expansion capital expenditures at Kildair for the crude oil storage and handling construction project, and $9.0 million relating to capital expenditure projects across our terminal system.

Net cash used in investing activities for the year ended December 31, 2012 was approximately $79.7 million and consisted primarily of $73.0 million related to our acquisition on October 1, 2012 of the remaining 50% of Kildair, and $7.3 million related to capital expenditure projects across our terminal system.

Financing Activities

Net cash provided by financing activities for the year ended December 31, 2014 was approximately $118.4 million. During 2014, the net cash provided by financing activities primarily resulted from net borrowings of $244.7 million under our credit agreement, partially offset by a distribution to parent for the contribution of Kildair of $56.7 million and $31.6 million paid to unitholders.

Net cash provided by financing activities for the year ended December 31, 2013 was approximately $126.0 million. During 2013, the net cash provided by financing activities primarily resulted from $140.3 million in net proceeds (net of underwriting and structuring fees and other offering expenses) from our IPO, net borrowings of $28.4 million under our credit agreement, partially offset by a distribution of $40.0 million paid to Axel Johnson and debt issuance costs of $16.7 million.

Net cash used in financing activities for the year ended December 31, 2012 was approximately $111.6 million. During 2012, the net cash used in financing activities primarily resulted from $107.8 million of net payments under the credit agreement and a $26.9 million dividend to Axel Johnson partially offset by borrowings of $25.0 million from a third party relating to the financing of the remaining 50% purchase of Kildair s equity.

Credit Agreement

On December 9, 2014, in connection with the acquisition of Kildair, Sprague, the operating company of the Partnership, Sprague Resources ULC and Kildair entered into an amended and restated revolving credit agreement (the Credit Agreement). Capitalized terms used but not otherwise defined in this section entitled Credit Agreement are used as defined in the Credit Agreement. This $1.5 billion Credit Agreement will mature on December 9, 2019. The revolving credit facilities under the Credit Agreement contain, among other items, the following:

A U.S. dollar revolving working capital facility of up to $1.0 billion to be used for working capital loans and letters of credit;

A multicurrency revolving working capital facility of up to $120.0 million to be used by Sprague s Canadian subsidiaries for working capital loans and letters of credit;

A revolving acquisition facility of up to $400.0 million to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to Sprague s current businesses; and,

Subject to certain conditions, the U.S. dollar and multicurrency revolving working capital facilities may be increased by $200.0 million in the aggregate. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

The Partnership and each of its subsidiaries are guarantors of all obligations under the Credit Agreement. All obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

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

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

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

The specified margin for the working capital facilities under the Credit Agreement 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. In addition, Sprague will incur a commitment fee based on the unused portion of the U.S. dollar working capital facility and the multicurrency working capital facility at a rate ranging from 0.375% to 0.50% per annum.

The specified margin for the acquisition facility under the Credit Agreement will range, based on Sprague s consolidated total leverage ratio, from 2.00% to 2.25% for loans bearing interest at the alternate Base Rate and from 3.00% to 3.25% for loans bearing interest at the Eurocurrency Rate and for letters of credit issued under the acquisition facility. In addition, Sprague will incur a commitment fee on the unused portion of the acquisition facility at a rate ranging from 0.375% to 0.50% per annum.

The Credit Agreement contains various covenants and restrictive provisions that, among other things, prohibit the Partnership from making distributions to unitholders if any event of default occurs or would result from the distribution or if the Partnership would not be in pro forma compliance with its financial covenants after giving effect to the distribution. In addition, the Credit Agreement contains various covenants that are usual and customary for a financing of this type, size and purpose, including, among others:

a minimum consolidated EBITDA-to-fixed charge ratio of 1.2:1.0;

a requirement of minimum consolidated Net Working Capital of $35,000,000;

a maximum consolidated total leverage-to-EBITDA ratio of 5.5:1.0 for any fiscal quarter ending on or prior to June 30, 2015 and a maximum consolidated total leverage-to-EBITDA ratio of 4.75:1.0 thereafter;

maximum consolidated senior secured leverage-to-EBITDA ratio of 4.5:1.0 for any fiscal quarter ending on or prior to June 30, 2015 and a maximum consolidated senior secured leverage-to-EBITDA ratio of 3.75:1.0 thereafter; and,

covenants limiting the ability of Sprague and its subsidiaries to incur debt, grant liens, make certain investments or acquisitions, dispose of assets, and incur additional indebtedness.

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

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 years ended December 31, 2014, 2013 and 2012.

Foreign Currency

Prior to December 31, 2013, the functional currency of Kildair was the Canadian dollar. All balance sheet asset and liability accounts were translated to U.S. dollars using rates of exchange in effect at the balance sheet dates, and its results of operations were translated using average exchange rates for the relevant period. Resulting translation adjustments were recorded as a component of member s equity in accumulated other comprehensive loss.

On January 1, 2014, we changed the functional currency of Kildair from the Canadian Dollar to the U.S. Dollar as a result of performing a review of the appropriateness of the status of the functional currency for this subsidiary. The factors we considered included an increasing portion of Kildair s business being conducted in U.S. dollars, as well as the fact that during the year ended December 31, 2013, Kildair entered into a new credit facility that is denominated in U.S. dollars. The functional currency of Kildair s subsidiaries remains the Canadian Dollar. Our reporting currency is the U.S. dollar. In accordance with ASC-830 Foreign Currency Matters , the change took place prospectively on the first day of the fiscal year, there was no income statement or cash flow translation required and the translation adjustments for prior periods were not removed from equity.

Critical Accounting Policies and Estimates

Use of Estimates

The Partnership s Consolidated and Combined Financial Statements have been prepared in accordance with GAAP. The preparation of these Consolidated and Combined 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 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:

Derivatives

As a matter of policy, refined products and natural gas businesses utilize futures contracts, forward contracts, swaps, options and other derivatives in an effort to minimize the impact of commodity price fluctuations. On a selective basis and within our risk management policy s guidelines, we utilize futures contracts, forward contracts, swaps, options and other derivatives to generate profits from changes in market prices.

We record all derivative instruments as either assets or liabilities in the statement of financial position and measure those instruments at fair value. We recognize changes in the fair value of our commodity derivative instruments currently in earnings as cost of products sold.

We do 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 fair value amounts, including amounts that approximate fair value, recognized for derivative instruments executed with the same counterparty under the same master netting arrangement.

We also use interest rate swaps to convert a portion of our floating rate debt to fixed rates. These interest rate swaps are designated as cash flow hedges and the changes in fair value of the swaps are included as a component of comprehensive income (loss) and accumulated other comprehensive loss, net of tax, in our Consolidated and Combined Statements of Member s/Unitholders Equity and in our Consolidated Balance Sheets, respectively.

Our derivative instruments are recorded at fair value, with changes in fair value recognized in net income (loss) or other comprehensive income (loss) each period as appropriate. Fair value measurements are determined using the market approach and include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for payable balances.

We determine fair value in accordance with Accounting Standards Codification (ASC) 820, Fair Value Measurement which established a hierarchy for the inputs used to measure the fair value of financial assets and liabilities based on the source of the input, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using significant unobservable inputs (Level 3). Multiple inputs may be used to measure fair value; however, the level of fair value is based on the lowest significant input level within this fair value hierarchy.

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

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

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange traded curve, but have contractual terms that are not identical to exchange traded contracts. We utilize fair value measurements based on Level 2 inputs for our 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.

Inventories

We value inventories at the lower of cost or market. Cost is primarily determined using the first-in, first-out method. Inventory consists of petroleum products, natural gas and coal. We use derivative instruments, primarily futures and swaps, to economically hedge substantially all of our inventory.

Goodwill

Goodwill is defined as the excess of cost over the fair value of assets acquired and liabilities assumed in a business combination. We review the carrying value of goodwill annually as of October 31st or on an as needed basis, for indicators of impairment at each reporting unit that has recorded goodwill. Impairment is indicated whenever the carrying value of a reporting unit exceeds the estimated fair value of a reporting unit.

For purposes of evaluating impairment of goodwill, we estimate the fair value of a reporting unit based upon future net discounted cash flows (Level 3 measurement). In calculating these estimates, historical operating results and anticipated future economic factors, such as estimated volumes and demand for services, commodity prices, and operating costs are considered as a component of the calculation of future discounted cash flows. Further, the discount rate requires estimates of the cost of equity and debt financing. The estimates of fair value of these reporting units could change if actual volumes, prices, costs or discount rates vary from these estimates. These assumptions contemplated business, market and overall economic conditions. We performed sensitivity analyses on the fair values resulting from the discounted cash flows valuation utilizing more conservative assumptions that reflect reasonably likely future changes in the discount rates and perpetual growth rate in each of the reporting units. Based upon our 2014 annual impairment testing analyses, including the consideration of reasonably likely adverse changes in assumptions described above, we believe it is not reasonably likely that an impairment will occur in any of the reporting units over the next twelve months.

Net Sales and Cost of Products Sold Recognition

Revenue is recognized through refined products, natural gas and materials handling revenue-producing activities, net of non-material provisions for discounts and allowances. At the time of sale for all revenue producing activities, persuasive evidence of an arrangement exists, delivery or service has occurred, the price is determinable and collectability is reasonably assured. Refined products revenue-producing activities include direct sales to customers including throughput and exchange locations. 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 end markets. Any net differentials or fees for exchange agreements are recorded as cost of goods sold. Natural gas revenue-producing activities are sales to customers at various points on natural gas pipelines or at local distribution companies (*i.e.*, utilities). Revenue is recognized when the product is delivered. Materials handling service revenue is recognized monthly over the contractual service period or when the service is rendered.

The allowance for doubtful accounts is recorded to reflect the ultimate realization of our accounts receivable and includes the assessment of customers creditworthiness and the probability of collection. The allowance is comprised of specifically identified accounts at risk and an amount determined based on historical collection experience.

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Shipping costs that occur at the time of sale are included in cost of product sold. Various excise taxes are collected at the time of sale and remitted to authorities and are recorded on a net basis in cost of products sold.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standard Update 2014-09, *Revenue from Contracts with Customers*, 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. We continue to evaluate both the impact of this new standard on the consolidated financial statements and the transition method we will utilize for adoption. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted.

In April 2014, the Financial Accounting Standards Board issued Accounting Standard Update 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. This ASU revises the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. We have early adopted this guidance on a prospective basis. The adoption did not have a material impact on our consolidated financial statements.

Item 7A. 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 forward starting swaps to manage exposure to interest rate risk.

Commodity Price Risk

We use various financial instruments to hedge our commodity price risk. We sell our refined products and natural gas primarily in the Northeast United States and Quebec, Canada. This geographic focus is a key factor in how we choose the most appropriate financial instruments to hedge our positions.

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 that are bilateral contracts that are traded over-the-counter. 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 oils futures contracts. 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

In addition to the financial instruments listed above, we sometimes 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.

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

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price exposure using fixed-for-floating price swaps that trade on the 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 physically by using forward purchases or sales.

The following table presents total realized and unrealized (losses) and gains on derivative instruments utilized for commodity risk management purposes. Such amounts are included in cost of products sold for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012 Predecessor
Refined products contracts	$ 159,751	$ (320)	$ (7,238)
Natural gas contracts	30,372	(76,707)	(19,580)
Total	$ 190,123	$ (77,027)	$ (26,818)

Substantially all of our commodity derivative contracts outstanding as of December 31, 2014 will settle prior to June 30, 2016.

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. At December 31, 2014, the Partnership held three interest rate swap agreements with a notional value of $100.0 million with swap periods that expire in January 2015. In addition, the Partnership held six interest rate swaps with a total notional value of $175.0 million whose swap periods begin in January 2015, expiring in January 2016; and five interest rate swaps with a total notional value of $150.0 million whose swap periods begin in January 2016, expiring in January 2017. 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. Borrowings under our credit agreement bear interest, at our option, at a rate per annum equal to the Eurocurrency Rate (which means the LIBOR Rate) or the Alternate Base Rate which means the highest of (a) the prime rate of interest announced from time to time by the agent as its Base Rate, (b) 0.50% per annum above the Federal Funds Rate as in effect from time to time and (c) the Eurocurrency Rate for 1-month LIBOR as in effect from time-to-time plus 1.00% per annum, depending on which facility is being used. During the two year period ended December 31, 2014, we hedged approximately 36% of our floating rate debt with fixed-for-floating interest rate swaps. We report unrealized gains and losses on the interest rate swaps as a component of accumulated other comprehensive income or loss, net of taxes, which is reclassified to earnings as interest expense when payments are made. We expect to continue to utilize interest rate swaps to manage our exposure to LIBOR interest rates. Based on a sensitivity analysis for the year ended December 31, 2014, it was estimated that if short-term interest rates average 100 basis points higher (lower), interest expense would increase by approximately $2.8 million and decrease by approximately $0.4 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.

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Derivative Instruments

The following tables present all of our financial assets and financial liabilities measured at fair value on a recurring basis as of December 31, 2014:

	Fair Value Measurement		Active Markets Level 1		Observable Inputs Level 2		Unobservable Inputs Level 3
Financial assets:							
Commodity fixed forwards	$	229,679	$		$	229,679	$
Commodity swaps and options		74				74	
Commodity derivatives		229,753				229,753	
Interest rate swaps		137				137	
Total	$	229,890	$		$	229,890	$
Financial liabilities:							
Commodity exchange contracts	$	97	$	97	$		$
Commodity fixed forwards		80,080				80,080	
Commodity swaps and options		8,424				8,424	
Commodity derivatives		88,601		97		88,504	
Interest rate swaps		553				553	
Currency swaps		22				22	
Total	$	89,176	$	97	$	89,079	$

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 volatility of 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. Controls include volumetric, value at risk and stop loss limits on discretionary positions as well as contract term limits. Our Chief Risk Officer 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 value at risk to monitor and control 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, and accepting personal guarantees and various 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.

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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.

The following table presents the value at risk for our refined products and natural gas marketing and risk management commodity derivatives activities:

	Refined Products		Natural Gas	
	2014	2013	2014	2013
	(in thousands)		(in thousands)	
At December 31	$ 315	$ 369	$ 282	$ 389
Average	219	168	296	293
High	815	369	617	687
Low	58	72	105	130

Item 8. Financial Statements and Supplementary Data

See Part IV, Item 15 Index to Consolidated and Combined Financial Statements .

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2014. The term disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2014, our Chief Executive Officer and Chief Financial Officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management s Report Regarding Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal control over financial reporting may vary over time.

In October 2014 and December 2014, Sprague Resources LP acquired Metromedia Gas and Power, Inc., Castle Oil, and Kildair for $32.8 million, $92.2 million, and $175.0 million, respectively (the 2014 acquisitions). Since Sprague Resources LP has not yet fully incorporated the internal controls and procedures of the 2014

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acquisitions into Sprague Resources LP s internal control over financial reporting, management excluded this business from its assessment of the effectiveness of internal control over financial reporting as of December 31, 2014. The 2014 acquisitions accounted for $390.9 million and $47.2 million of Sprague Resources LP s total assets and net assets, respectively, as of December 31, 2014 and $582.5 million and $6.9 million of net sales and net income, respectively, for the year then ended.

Management has assessed the effectiveness of Sprague Resources LP s internal control over financial reporting as of December 31, 2014, with the exception of the aforementioned 2014 acquisitions. In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission in Internal Control Integrated Framework (2013 Framework). Management concluded that based on its assessment, Sprague Resource s internal control over financial reporting was effective as of December 31, 2014. Ernst & Young LLP, Registered Public Accounting Firm included in this annual report, has issued an attestation report on our internal control over financial reporting, which appears on page F-3.

Changes In Internal Control Over Financial Reporting

There have been no changes in our system of internal control over financial reporting during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the Partnership s internal control over financial reporting.

It em 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers and Directors of our General Partner

Our general partner oversees our operations and activities on our behalf through its board of directors. The board of directors of our general partner appoints our officers, all of whom are employed by the general partner and manage our day-to-day affairs. Neither our general partner, nor the board of directors of our general partner, is elected by our unitholders and neither will be subject to re-election in the future. Rather, the directors of our general partner are appointed by Sprague Holdings, which owns 100% of our general partner. Our board of directors met seven times during the 2014 fiscal year and each of its directors attended all of the meetings and also attended all of the meetings for any committee on which they served.

The following table provides information as of March 9, 2015 for the executive officers and directors of our general partner. References to our officers, our directors, or our board refer to the officers, directors, and board of directors of our general partner. Directors are appointed to hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board.

Name	Age	Position with our General Partner
Michael D. Milligan	51	Chairman of the Board of Directors
Ben J. Hennelly	44	Director
Sally A. Sarsfield	55	Director
Robert B. Evans	66	Director
C. Gregory Harper	50	Director
Beth A. Bowman	58	Director
David C. Glendon*	49	President, Chief Executive Officer and Director
Gary A. Rinaldi*	57	Senior Vice President, Chief Operating Officer, Chief Financial Officer and Director
Thomas F. Flaherty*	59	Vice President, Refined Products
Steven D. Scammon*	53	Vice President, Chief Risk Officer
Joseph S. Smith*	58	Vice President, Business Development
Paul A. Scoff*	55	Vice President, General Counsel, Chief Compliance Officer and Secretary
John W. Moore*	56	Vice President, Chief Accounting Officer and Controller
James Therriault*	54	Vice President, Materials Handling
Burton S. Russell	59	Vice President, Operations
Brian W. Weego*	48	Vice President, Natural Gas
Frank B. Easton	68	Vice President, Human Resources
Kevin G. Henry	54	Vice President, Treasurer

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

Michael D. Milligan Mr. Milligan was appointed chairman of the board of directors of our general partner in July 2011. Mr. Milligan formerly served as a member of the board of directors of our predecessor and is the President & Chief Executive Officer of Axel Johnson, a position he has held since 2003. Prior to joining Axel Johnson, Mr. Milligan spent 17 years as a partner and member of the board of directors of Monitor Group, a global consulting and merchant banking group. While at Monitor, Mr. Milligan s activities covered a broad range of disciplines and industry sectors, including oil and gas, communications technology, specialty chemicals and retail and consumer products. Mr. Milligan holds a Bachelor of Arts degree from Bowdoin College and a Masters in Business Administration from Harvard University. We believe that Mr. Milligan s more than 20 years of experience in the energy industry, as well as his extensive management skills he acquired through his involvement in the strategy, operations and governance of Axel Johnson, brings substantial perspective and leadership to our board.

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Ben J. Hennelly Mr. Hennelly was appointed to the board of directors of our general partner in July 2011. Mr. Hennelly currently serves as the Executive Vice President of Axel Johnson, a position he has held since March 13, 2007. Mr. Hennelly also currently serves as President and Chief Financial Officer of Decisyon Inc., an Axel Johnson portfolio company, which develops and markets enterprise collaboration software in the U.S. and Europe. Mr. Hennelly previously served as Chief Financial Officer for Axel Johnson during the period of March 2007 through June 2012. Mr. Hennelly has held various positions within the Axel Johnson Group since joining our predecessor in April 2003, including Vice President, Business Development of our predecessor and, more recently, Vice President, Corporate Development at Axel Johnson. Before joining the Axel Johnson Group, Mr. Hennelly was on the founding management team of EPIK Communications, a provider of broadband telecom services, and previously was a consultant with the Monitor Group, a global management strategy consulting firm, where he advised clients across a range of industries, including the energy industry. Mr. Hennelly holds a Bachelor of Arts degree from Cornell University and a PhD from Brown University. We believe that Mr. Hennelly s 16 years of consulting and management experience in a variety of industries, together with his deep understanding of our business from nearly three years of service at our predecessor, make Mr. Hennelly well-suited to serve on the board of directors of our general partner.

Sally A. Sarsfield Ms. Sarsfield was appointed to the board of directors of our general partner in February 2015. She currently serves as Chief Financial Officer of Axel Johnson, a position she has held since June 2012. Ms. Sarsfield initially joined Axel Johnson as the VP Finance and Administration in July, 2010. Previously Ms. Sarsfield was the Chief Financial Officer of RA Capital Management, LLC, an investment management firm operating a long/short equity healthcare hedge fund. Prior to that, Ms. Sarsfield was a Partner and Co-Founder of BlueStar Capital Management LP, a firm specializing in healthcare investing via funds of hedge funds where she served as Chief Financial Officer, Partner and investment analyst for seven years. Ms. Sarsfield spent the first seven years of her career in a variety of roles with W.R. Grace & Co. including Senior Financial Analyst, Project Manager, Business Development and Director of Financial Planning and Analysis for one of its operating groups. Ms. Sarsfield holds a Bachelor of Arts in Biology from the University of Virginia. She spent a year in the University of Chicago Division of Biological Sciences Ph.D. program in Molecular Genetics before going on to get a Master s in Business Administration from the University of Chicago. We believe the combination of Ms. Sarsfield s years of business and investment management experience, in addition to her expertise in financial oversight, prepare her well to serve on the board of directors of our general partner.

C. Gregory Harper Mr. Harper was appointed to the board of directors of our general partner in October 2013 in connection with our IPO. On January 30, 2014, Mr. Harper was appointed President, Gas Pipelines and Processing for Enbridge Inc., a North American leader in delivering energy. On February 28, 2014, Mr. Harper was also appointed as the principal executive officer of Midcoast Holdings, L.L.C. Before joining Enbridge, Mr. Harper served as Senior Vice President of Midstream of Southwestern Energy Company, from August 2013 to January 2014. Before joining Southwestern Energy, Mr. Harper served as Senior Vice President and Group President of CenterPoint Energy Pipelines and Field Services from December 2008 to June 2013. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December 2008. From January 2007 to March 2007, Mr. Harper was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. Mr. Harper currently serves on the board of directors of the Interstate Natural Gas Association of America, Midcoast Holdings, L.L.C., Enbridge Energy Company, Inc. and Enbridge Energy Management, L.L.C. Mr. Harper received his Bachelor s degree in Mechanical Engineering from the University of Kentucky and his Master s degree in Business Administration from the University of Houston. We believe Mr. Harper s extensive industry background, particularly his financial reporting and oversight expertise, will bring important experience and skill to the board of directors of our general partner.

Robert B. Evans Mr. Evans was appointed to the board of directors of our general partner in October 2013 in connection with our IPO. Mr. Evans has also served as a director of the general partner of Targa Resources Partners, LP since February 2007, as a director of New Jersey Resources Corporation since 2009, and as a director of ONE Gas, Inc. since 2014. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 to March 2006, after which he retired. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998. Mr. Evans received his Bachelor s degree in Accounting from the University of Houston. We believe Mr. Evans s extensive energy industry background, particularly his experience in senior leadership roles and board positions of other energy companies, will provide the board of directors of our general partner with valuable knowledge and skill.

Beth A. Bowman Ms. Bowman was appointed to the board of directors of our general partner in October 2014. Ms. Bowman has served at Shell Energy North America for the past fifteen years where she is currently the Senior Vice President for Sales and Origination North America. Prior to joining Shell, Ms. Bowman held management positions at Sempra Energy Trading and Sempra s San Diego Gas & Electric utility. In 2014, Ms. Bowman was named one of the Top 50 Most Powerful Women in Oil and Gas in the U.S. by the National Diversity Council. Ms. Bowman currently serves on the boards of the California Power Exchange and the California Foundation of Energy and Environment. Ms. Bowman received her Bachelor s degree in Science Civil Engineering from the University of Illinois, a Master s degree in Science Civil Engineering from San Diego State University and a Master s degree in Business Administration Finance from University of San Diego. We believe that Ms. Bowman s extensive energy industry background, particularly her experience in senior leadership roles and board positions of other energy companies, will provide the board of directors of our general partner with valuable knowledge and skill.

David C. Glendon Mr. Glendon was appointed to the board of directors of our general partner and was named President and Chief Executive Officer of our general partner in July 2011, a position he held with our predecessor since January 15, 2008. Mr. Glendon was hired by our predecessor on June 30, 2003 as the Senior Vice President of Oil and Materials Handling, focusing on driving the execution of a customer-centric approach across all elements of the business. Prior to joining our predecessor, Mr. Glendon was a partner and global account manager at Monitor Group. He was also a founder and managing director of Monitor Equity Advisors, which worked with leading private capital providers in evaluating transactions and enhancing the strategic positions of their portfolio investments. Mr. Glendon received a Bachelor s degree, cum laude, in Psychology from Williams College and a Master s degree in Business Administration from the Stanford Graduate School of Business. As a result of his professional background, we believe Mr. Glendon brings executive-level strategic and financial skills along with significant operational experience that, when combined with his 15 years of consulting experience in a variety of industries and a deep knowledge of our business, make Mr. Glendon well-suited to serve on the board of directors of our general partner.

Gary A. Rinaldi Mr. Rinaldi was appointed to the board of directors of our general partner, and was named Senior Vice President, Chief Operating Officer and Chief Financial Officer of our general partner, in July 2011, a position he held with our predecessor since January 15, 2008. In such role, Mr. Rinaldi has responsibility for all terminals, materials handling and trucking operations, in addition to his duties as Chief Financial Officer. Mr. Rinaldi has been continuously employed by our predecessor since he was hired on April 27, 2003 as Senior Vice President and Chief Financial Officer. Prior to joining our predecessor, Mr. Rinaldi was Managing Director and Chief Financial Officer for the SUN Group. Prior to that, Mr. Rinaldi held several senior financial and operational management positions at Phibro Energy, a division of Salomon Inc., including Vice President and Chief Financial Officer and Director of Phibro Energy Production Inc. Mr. Rinaldi received his Bachelor s degree in Economics with a concentration in Accounting from The Wharton School, The University of Pennsylvania and is a former Certified Public Accountant.

We believe that Mr. Rinaldi s experience with our predecessor plus his 22 years of prior experience in a variety of senior financial and operational management roles in the energy industry, when combined with his past service on multiple boards of directors, allows him to bring substantial experience and leadership skills to the board of directors of our general partner.

Thomas F. Flaherty Mr. Flaherty was appointed Vice President, Refined Products of our general partner in February, 2014 with responsibility for all activities in the business unit including Marketing, Supply, and Pricing. Previously, Mr. Flaherty was appointed to the position of Vice President, Sales of our general partner in July 2011, a position he held with our predecessor since November 28, 2006. In that role, Mr. Flaherty was responsible for all refined products sales and marketing activities. Mr. Flaherty has served in various roles during his continuous tenure with our predecessor since he was hired as an Account Executive in Coal Sales in July 1983, including Vice President, Commercial Sales and subsequently Vice President, Industrial Marketing. Prior to joining our predecessor, Mr. Flaherty was employed by Eastern Associated Coal Corp, a Pittsburgh based coal production company. Mr. Flaherty received his Bachelor s degree in Management from the University of Massachusetts and a Master s degree in Business Administration from the Whittemore School of Business, University of New Hampshire.

Steven D. Scammon Mr. Scammon was appointed Vice President, Chief Risk Officer of our general partner in February, 2014 with duties including overseeing risk management and related control processes, including all middle office activities and insurance groups. Previously, Mr. Scammon was appointed to the position of Vice President, Trading and Pricing of our general partner in July 2011, a position he held with our predecessor since January 28, 2008. In that role, Mr. Scammon was responsible for refined products trading and pricing. Mr. Scammon also managed customer service until February 2013 at which time it was moved into marketing. Mr. Scammon joined our predecessor as Vice President, Clean Products on December 26, 2000 and has been continuously employed by our predecessor since then. Prior to joining our predecessor, Mr. Scammon served as Senior Vice President with the Consolidated Natural Gas Energy Services Co. Prior to that, Mr. Scammon served in several positions with Louis Dreyfus Corporation including as Global Position Manager and Manager National Accounts. Mr. Scammon received his Bachelor s degree in Economics from Denison University.

Joseph S. Smith Mr. Smith was appointed Vice President, Business Development of our general partner in February, 2014 where he will lead acquisition sourcing and integration efforts in addition to overseeing the company s Sarbanes-Oxley compliance process. Previously, Mr. Smith was appointed Vice President, Chief Risk Officer and Strategic Planning of our general partner in July 2011, a position he held with our predecessor since July 3, 2006. In such role, Mr. Smith was tasked with oversight responsibility for risk management and related control processes. As part of that role, he had management responsibility for strategic planning, financial planning and analysis, middle office, and insurance groups. Mr. Smith has been an employee of our predecessor since April 2001 when he joined as Vice President, Corporate Planning and Development and was subsequently promoted to Vice President, Pricing and Performance Management. Prior to joining our predecessor, Mr. Smith was a Principal with Arthur D. Little, Inc. s international energy consulting practice. He also worked in various positions for Mobil Oil Corporation, including in the areas of sales and supply and research and development. Mr. Smith received his Bachelor s degree in Chemical Engineering from the University of Maine. He received a Master s degree in Chemical Engineering from Pennsylvania State University and a Master s degree in Business Administration in Finance from Drexel University.

Paul A. Scoff Mr. Scoff was appointed Vice President, General Counsel, Chief Compliance Officer and Secretary of our general partner in July 2011, a position he held with our predecessor since June 1, 2011. Mr. Scoff has been continuously employed by our predecessor since December 1999, serving as Vice President, General Counsel and Secretary during such time. Prior to joining our predecessor, Mr. Scoff was the Vice President and General Counsel of Genesis Energy L.P., a publicly traded master limited partnership. Prior to Genesis, Mr. Scoff served as Senior Counsel with Basis Petroleum (formerly known as Phibro Energy U.S.A. Inc., a division of Salomon Inc.). He also served as Senior Counsel with The Coastal Corporation prior to joining Basis Petroleum. He received his Juris

Doctorate from the University of Houston Law Center and his Bachelor s degree, cum laude, in Political Science and English from Washington and Jefferson College.

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John W. Moore Mr. Moore was appointed Vice President, Chief Accounting Officer and Controller of our general partner in July 2011 and is responsible for our financial reporting, a position he held with our predecessor. Mr. Moore has been continuously employed by our predecessor since joining in June 1998 as the Chief Accounting Officer and Controller. Prior to joining our predecessor, Mr. Moore worked as an auditor at Arthur Andersen LLP and in various senior accounting management capacities at Phibro Energy and Valero Energy Corporation. Mr. Moore s accounting experience includes both his experience with our predecessor plus 15 years of prior experience in the energy industry. Mr. Moore received a Bachelor s degree, magna cum laude, in Accounting from Texas Tech University and is a Certified Public Accountant.

James A. Therriault Mr. Therriault was appointed Vice President, Materials Handling of our general partner in July 2011, a position he held with our predecessor since October 2003. As Vice President, Materials Handling, Mr. Therriault is responsible for the sales and business development efforts of our materials handling business unit. Mr. Therriault has held a variety of business and financial positions since joining our predecessor in 1984. Mr. Therriault graduated from The University of New Hampshire with a Bachelor of Arts degree in Economics and from the University of Southern New Hampshire with a Master s degree in Business Administration.

Burton S. Russell Mr. Russell was appointed Vice President, Operations of our general partner in July 2011, a position he held with our predecessor since 2003. As Vice President, Operations, Mr. Russell is responsible for the safe, environmentally responsible and cost efficient operation of our terminals and fleet. He joined our predecessor in 1998 and has continuously served in various positions, including responsibilities for terminals, fleet, safety, regulatory compliance, engineering and materials handling. Prior to joining our predecessor, Mr. Russell spent 21 years as a commissioned officer in the U.S. Coast Guard, serving the majority of that time in their Marine Technical, Port Safety and Environmental Protection programs. His last duty assignment was as the Captain of the Port, Officer in Charge of Marine Inspection and Federal On Scene Coordinator at the Marine Safety Office located in Portland, Maine. Mr. Russell received a Bachelor of Science degree in Ocean Engineering from the U.S. Coast Guard Academy. He received two Master s degrees from the University of Michigan: one in Naval Architecture and Marine Engineering and a second in Mechanical Engineering. He is also a licensed Professional Engineer.

Brian W. Weego Mr. Weego was appointed Vice President, Natural Gas of our general partner in July 2011, a position he held with our predecessor since June 7, 2010. As Vice President, Natural Gas, Mr. Weego is responsible for all elements of the natural gas business unit. Mr. Weego has been continuously employed by our predecessor since he was hired on December 7, 1998, having served as Manager, Natural Gas Supply Operations; Director, Natural Gas Marketing; and Managing Director, Natural Gas Marketing. Prior to joining our predecessor, Mr. Weego spent 11 years in various segments in the natural gas industry and has worked for the Coastal Corporation (wholesale natural gas origination and sales), O&R Energy (natural gas supply and trading) and Commonwealth Gas Company (natural gas utility supply planning and acquisition). Mr. Weego received a Bachelor of Science degree in Management from Lesley University and a Master s degree in Business Administration from the University of New Hampshire Whittemore School of Business and Economics.

Frank B. Easton Mr. Easton was appointed Vice President, Human Resources of our general partner in July 2011, a position he held with our predecessor since August 3, 1998. He previously served in a consulting capacity for our predecessor beginning in March 1998. Prior to joining our predecessor, Mr. Easton served as a Director of Human Resources at Dell Computer Corporation and Sequent Computer Systems, and, prior thereto, he served in a variety of finance and human resources roles at Wang Laboratories. Mr. Easton received his Bachelor s Degree in Sociology from Keene State College and his Master s Degree in Business Administration from the Executive Program, Whittemore School of Business, University of New Hampshire.

Kevin G. Henry Mr. Henry was appointed Vice President, Treasurer of our general partner in March 2012. Previously he was appointed Treasurer of our general partner in July 2011, a position he held with our predecessor since October 1, 2003. His primary responsibilities include managing liquidity, banking

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relationships, cash management and interest rate hedging programs. Additionally, Mr. Henry has management responsibility for the credit department and contract administration. Prior to joining our predecessor, Mr. Henry was an Assistant Treasurer for nine years with Tosco Corporation, a publicly held integrated oil company with refining, marketing and retail service stations. Mr. Henry previously worked for Phibro in various financial capacities. Mr. Henry received a Bachelor s degree in Management from St. Francis College with further accreditations from the Graduate School of Credit and Financial Management at Dartmouth College and the American Graduate School of International Management at Thunderbird University.

Director Independence

NYSE rules do not require that the board of directors of our general partner be composed of a majority of independent directors. Nonetheless, the board of directors of our general partner has affirmatively determined that Ms. Bowman (who was appointed in October 2014) and Messrs. Evans and Harper meet the independence standards established by the NYSE.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee. Each of the standing committees of the board of directors has the composition and responsibilities described below. NYSE rules do not require us to have a compensation committee or a nominating/corporate governance committee. Ms. Bowman and Messrs. Evans and Harper are members of the audit committee and the conflicts committee.

Audit Committee

We are required to have an audit committee of at least three members and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act. Ms. Bowman and Messrs. Evans and Harper are the current members of our audit committee. The board of directors of our general partner has determined that each director appointed to the audit committee is financially literate, and Mr. Harper, who serves as chairman of the audit committee, has accounting or related financial management expertise and constitutes an audit committee financial expert in accordance with SEC and NYSE rules and regulations. The audit committee of the board of directors of our general partner serves as our audit committee and will assist the board in its oversight of the integrity of our consolidated financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee operates under a written charter and has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee and our management, as necessary. The audit committee met seven times during the 2014 fiscal year.

Conflicts Committee

The board of directors of our general partner has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of any such conflict of interest is fair and reasonable to us. The board of directors of our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The committee consists of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates (other than as directors of our subsidiaries) and each of whom must meet the independence standards for service on an audit committee established by the NYSE and the SEC. Ms. Bowman and Messrs. Harper and Evans are the independent members of the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders, and not a breach by our general partner of any duties it may owe us or our unitholders.

If the board of directors of our general partner does not seek approval from the conflicts committee, and the board of directors of our general partner approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of us or any unitholder, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Corporate Code of Business Conduct and Ethics

The board of directors of our general partner has approved a Corporate Code of Business Conduct and Ethics which is applicable to all directors, officers and employees of our general partner, including the principal executive officer and the principal financial officer. The Corporate Code of Business Conduct and Ethics is available on our website at http://www.spragueenergy.com/investor-relations (under the Corporate Governance tab) and in print without charge to any unit holder who sends a written request to our secretary at our principal executive offices. We intend to post any amendments of this code or waivers of its provisions applicable to directors or executive officers of our general partner, including its principal executive officer and principal financial officer, at this location on our website.

Procedures for Review, Approval and Ratification of Related Person Transactions

Under our Corporate Code of Business Conduct and Ethics, the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. Our Code of Business Conduct and Ethics and Partnership Agreement set forth policies and procedures with respect to transactions with related persons and potential conflicts of interest which, when taken together, provide a structure for the review and approval of transactions with related persons. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the Corporate Code of Business Conduct and Ethics provides that our management will make all reasonable efforts to cancel or annul the transaction.

The conflicts committee is authorized to review, evaluate and approve any potential conflicts of interest between Sprague Resources GP LLC and its affiliates, on one hand, and the Partnership, its subsidiaries, or any general partner or limited partner of the Partnership, on the other hand; and, the conflicts committee may engage consultants, attorneys, independent accountants and/or other service providers to assist in the evaluation of quantitative and/or qualitative material conflicts matters. Any such approval by the conflicts committee will constitute approval of such matter and no other action of the board of directors is required.

The Corporate Code of Business Conduct and Ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions; (iv) the impact of the transaction on a director s independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

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Current conflicts committee members include Mr. Evans, Mr. Harper and Ms. Bowman and these three members qualify as independent directors, satisfying the SEC and NYSE standards for independence as of the date herein.

Available Information

We make available, free of charge within the Investor Relations Corporate Governance section of our website at www.spragueenergy.com and in print to any unitholder who so requests, our Audit Committee charter, Corporate Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics, Insider Trading Policy, Short-Swing Trading and Reporting Policy and Whistleblower Policy. Requests for print copies may be directed to: Investor Relations, Sprague Resources LP, 185 International Drive, Portsmouth, New Hampshire 03801 or made by telephone by calling (800) 225-1560. The information contained on or connected to our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Pursuant to our Corporate Governance Guidelines, Mr. Milligan is the lead, non-management director and will preside over regularly scheduled executive sessions of the board of directors without management (Lead Director). To view the designated Lead Director and the method for communicating directly with the Lead Director, please see our website at www.spragueenergy.com.

Section 16(a) Beneficial Ownership Reporting Compliance

Each director, executive officer (and, for a specified period, certain former directors and executive officers) of our general partner and each holder of more than 10 percent of a class of our equity securities is required to report to the SEC his or her pertinent position or relationship, as well as transactions in those securities, by specified dates. Based solely upon a review of reports on Forms 3 and 4 (including any amendments) furnished to us during our most recent fiscal year and reports on Form 5 (including any amendments) furnished to us with respect to our most recent fiscal year, and written representations from officers and directors of our general partner that no Form 5 was required, we believe that all filings applicable to our general partner s officers and directors, and our beneficial owners, required by Section 16(a) of the Exchange Act were filed on a timely basis during 2014.

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Item 11. Executive Compensation

Compensation Committee Report

Neither we nor our general partner has a compensation committee. The non-management members of our board of directors of our general partner reviewed and discussed with management the section of this report entitled Compensation Discussion and Analysis and based on that review and discussion, approved its inclusion herein.

THE BOARD OF DIRECTORS
Michael D. Milligan
Robert Evans
C. Gregory Harper
Beth A. Bowman
Ben J. Hennelly
Sally A. Sarsfield

Compensation Discussion and Analysis

Introduction

Our general partner has sole responsibility for conducting our business and for managing our operations and its board of directors and officers make decisions on our behalf. We reimburse our general partner for the expenses associated with the services its employees provide to us, including compensation expenses for executive officers and directors of our general partner. The board of directors of our general partner has responsibility for establishing and evaluating the pay for the executive officers of our general partner.

The purpose of this Compensation Discussion and Analysis is to explain our philosophy for determining the compensation program for the Chief Executive Officer, the Chief Financial Officer and the three other most highly compensated executive officers of our general partner for 2014, referred in this report as the Named Executive Officers , and to discuss why and how the 2014 compensation package for these executives was implemented. Disclosure regarding our Named Executive Officers compensation for the 2014 fiscal year is disclosed in the tables below and discussed in this Compensation Discussion and Analysis. The Named Executive Officers for the fiscal year ending December 31, 2014 are as follows:

David C. Glendon President and Chief Executive Officer

Gary A. Rinaldi Senior Vice President, Chief Operating Officer and Chief Financial Officer

Thomas F. Flaherty Vice President, Refined Products

John W. Moore Vice President, Chief Accounting Officer and Controller

Joseph S. Smith Vice President, Business Development

Following this discussion are tables that include compensation information for the Named Executive Officers.

Objectives of Our Executive Compensation Program

Our executive compensation program is based on the following principles:

The compensation paid to our executives should be competitive with that paid to the executives of those companies with which we compete for executive talent so that we attract and retain a skilled and experienced management team.

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Incentive compensation should be a material portion of total compensation so that our executives are properly motivated to focus on achieving or exceeding our financial and business goals.

Unitholders should receive a threshold return on investment before the payout of any incentive compensation, so as to align the interests of the executive team with those of the unitholders.

The board of directors believes these objectives are best met by providing a mix of competitive base salaries in combination with short and long term cash compensation. This mix of compensation elements has provided us with a successful compensation program that has allowed us to attract and retain a quality team of executives while motivating them to provide a high level of performance.

Setting Executive Compensation

The board of directors has the responsibility and authority to make all decisions with regard to the compensation of our Named Executive Officers. The board of directors uses several different tools and resources in reviewing various elements of executive compensation and making compensation decisions.

Compensation Consultant

During 2014, the board chair outlined parameters and program expectations to guide efforts in developing a new compensation plan. Meridian Compensation Partners LLC (Meridian) as an independent consultant, provided advice on executive compensation matters. The decision to engage Meridian was made by the board of directors and Meridian reports directly and exclusively to the board of directors; however, at the direction of the board of directors, Meridian works directly with management to obtain information and prepare materials for the board of directors consideration. The board of directors has determined that Meridian s work did not raise any conflict of interest. In 2014, the board chair asked Meridian to assist in developing new annual and long term incentive compensation programs under the umbrella of the Sprague Resources LP 2013 Long Term Incentive Plan, which we refer to as the LTIP. Our goal was to better align these compensation programs with programs and best practices utilized by publicly traded companies in our industry, while ensuring the achievement of our executive compensation program objectives.

Meridian provided an external perspective on incentive compensation design by providing a summary of annual and long-term incentive practices for a group of similar companies (MLP, transportation and storage). They did this by providing:

Overall Structure

Metrics, Weightings, and Use of Discretion

Form of Payout

Length of Performance Period or Vesting

Form of Equity Vehicle

The mix between annual and long-term incentives for executive officers

Calculation of total unitholder return

Monte Carlo valuation of performance based phantom unit awards

Then, based on feedback from the board and Mr. Glendon, they developed a recommended plan design for both annual and long-term incentives.

The board of directors reviewed all of the information provided by Meridian and concluded that the new annual and long term incentive compensation programs described below would best achieve the Company s goals. These programs were approved by the board of directors in July of 2014. Please read the sections of this Compensation Discussion and Analysis that follow to obtain more detailed information about our new annual and long term incentive programs.

Role of Chief Executive Officer and Other Executive Officers in Determining Executive Compensation

When making determinations about each element of compensation for Named Executive Officers other than Mr. Glendon, our board of directors requests and carefully considers recommendations from Mr. Glendon. The board of directors may also ask Mr. Glendon and certain of our other executives to assess the design of, and make recommendations regarding, compensation and benefit programs and the performance measures and targeted levels of performance established thereunder. The board of directors is under no obligation to implement the recommendations received from these executives but may take them into consideration when making compensation decisions.

Components of Compensation

For the fiscal year ending December 31, 2014, the compensation for our Named Executive Officers consisted of the following elements:

- Base salary;
- Annual incentive bonus consisting of cash and units;
- Long term equity incentive awards; and
- Other benefits, including retirement and health and welfare and related benefits and in certain instances, the use of a car or a car allowance.

Base Salary

Each Named Executive Officer s base salary is a fixed component of compensation and does not vary depending on the level of performance achieved. Base salaries for the Named Executive Officers were historically set at levels deemed appropriate to retain their services. When establishing and evaluating base salary levels the board of directors generally considers the responsibilities associated with each Named Executive Officer s position, experience, skill, education, and potential to contribute to our overall success. For example, when the board of directors evaluates Mr. Glendon s role as President and Chief Executive Officer, the board of directors considers his prior experience and performance as Senior Vice President of Sales, as well as the additional responsibility he has in his current role as President and Chief Executive Officer. In establishing the base salaries for the rest of our Named Executive Officers, the board of directors also considers the extent to which the particular individual had the skills to help us solve the challenges we face and the expertise to help us meet our future business goals. Finally, the board of directors considers the other employment opportunities available to the executive and earning potential associated with those opportunities.

Base salaries for each Named Executive Officer are reviewed annually by the board of directors as well as at the time of any promotion or significant change in job responsibilities and, in connection with each review, individual and company performance over the course of that year are considered. Mr. Glendon makes recommendations with regard to base salary levels for Named Executive Officers other than himself and the Board takes these recommendations into account when reviewing base salary levels. Historically, when the board of directors determined it was appropriate, they utilized broad-based third-party compensation surveys in order to obtain a general understanding of current compensation practices. The board of directors did not use the information contained in these surveys to benchmark compensation, but rather to ensure that our pay practices were generally in line with the market. The board of directors did not utilize third-party surveys in its review of compensation levels for Named Executive Officers during 2014.

In 2015, following a review of base salary levels for each Named Executive Officer other than himself, Mr. Glendon recommended, and the board of directors approved, slight increases in the base salaries of Messrs. Flaherty, Moore and Smith. This decision was made in an attempt to balance our desire to retain the services of these officers in a competitive employment market and account for slight increases in the cost of living.

The board of directors chose not to increase the base salaries for Messrs. Glendon and Rinaldi at this time, choosing instead to focus on variable compensation. The 2015 increases below will become effective on March 31, 2015 for Messrs. Flaherty, Moore and Smith.

Name	March 2015 Base Salaries		March 2014 Base Salaries		April 2013 Base Salaries	
David C. Glendon	$	350,000	$	350,000	$	350,000
Gary A. Rinaldi	$	350,000	$	350,000	$	350,000
Tomas F. Flaherty	$	258,233	$	253,170	$	248,206
John W. Moore	$	250,335	$	246,636	$	241,800
Joseph S. Smith	$	243,296	$	238,524	$	232,707

We believe that the competitive base salaries we pay to our Named Executive Officers help us to satisfy the objectives of our executive compensation program by attracting and retaining experienced executive talent. Additionally, by providing our Named Executive Officers with competitive base salaries, we mitigate risk by providing those individuals with a portion of their income that is not subject to change based on our financial performance.

Annual Incentive Bonus

A significant portion of the total compensation for each of our Named Executive Officers is paid in the form of an annual bonus consisting of cash and units. While base salaries offer an important retention tool by providing a guaranteed income stream to our employees, we seek to incentivize and motivate employees to strive for both individual and overall company success by providing a substantial portion of their compensation in the form of discretionary annual bonus in cash and units so that our employees may share in the profits of the enterprise. Further, we feel that our industry has historically relied heavily on performance-based bonuses to compensate executive officers, and we want our compensation program to be consistent with industry trends and practices.

An annual incentive compensation pool has historically been established following the end of the fiscal year and used to fund both our annual and long term cash bonus programs for that year. The pool was typically funded based on a percentage of earnings before taxes from operations accrued for the year in question over and above a pre-established threshold level of earnings, which ensured a minimum rate of return was achieved for our owners. Our new annual incentive bonus program is administered under the umbrella of the Sprague Resources LP 2013 Long-Term Incentive Plan. When designing this new program, our board of directors wanted to retain the focus our historic program had on ensuring that our owners received a threshold return on investment before the payout of any incentive compensation, but wanted to ensure that the metrics used under the new program better reflected a return on investment for all of our unitholders. With that in mind, our board of directors determined that payments under our new annual incentive program should be contingent upon the achievement of distributable cash flow targets. The board established a minimum distributable cash flow threshold of $1.65 per unit for the 2014 annual incentive bonus pool that must be met before the pool starts to fund. As distributable cash flow increases the 2014 annual bonus pool incrementally increases.

In achieving distributable cash flow of $74.9 million, a bonus pool for all employees of our general partner was funded in the amount of $13.3 million. A majority of the bonus pool was paid in cash; however, certain of our executives received payment of both cash and common units.

When setting annual incentive bonus targets for the Named Executive Officers the board of directors took into consideration each Named Executive Officer s position within the company as well as their relative level of

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responsibility and their ability to directly impact our success. The targets for Messrs. Flaherty, Moore and Smith are each set at 50% of their base salary, which is consistent with other employees serving at the Vice President level. The target for Messrs. Glendon and Rinaldi is set at 100% of their base salary in order to reflect the additional responsibilities associated with their respective positions. Under the 2014 annual incentive bonus program, the cash bonus amounts deliverable to the Named Executive were capped at 150% of the individual bonus target levels. The Named Executive Officers were eligible to earn annual incentive bonus amounts for performance above that level, but any such amounts were required to be paid in units rather than cash. Units distributed under the annual incentive bonus program to the Named Executive Officers are fully vested but are subject to a one year holding period from date of issuance. Our board of directors believes that paying these amounts in common units with resale restrictions further aligns the interests of our Named Executive Officers with those of our unitholders.

The annual cash bonus received by each Named Executive Officer is initially calculated based on the total bonus pool. So for example, if the pool was 120% of the sum of all target bonuses, then the starting place for the Named Executive Officer bonus would be 120% times their target. Then Mr. Glendon will recommend a higher or lower bonus based on that Named Executive Officer s personal performance as well as the performance of his organization throughout 2014. Mr. Glendon submits his recommendations to the board of directors, who will review and discuss. If the board agrees with the recommendations, then they will approve the awards. However, the board has the right to increase or decrease recommendations based upon their judgment.

The amounts reflected in the table below are included in the Non-Equity Incentive Compensation column to the Summary Compensation Table, below. For 2014, the board of directors awarded the following annual bonus dollars and units to the Named Executive Officers:

Name	**2014 Cash Bonus**	**2014 Bonus Total Units**	**2014 Bonus Unit Grant Date Fair Value**
David C. Glendon	$ 525,000	27,811	$ 684,151
Gary A. Rinaldi	$ 525,000	27,811	$ 684,151
Thomas F. Flaherty	$ 189,878	12,335	$ 303,441
John W. Moore	$ 184,977	8,971	$ 220,687
Joseph S. Smith	$ 178,893	10,541	$ 259,309

The bonus unit grant date fair value listed above that is attributable to the value of the common units is based on the grant date fair value of those common units, as calculated pursuant to FASB ASC Topic 718.

Long Term Equity Incentive Awards

Our general partner adopted our LTIP in October of 2013. Unlike our Predecessor s long term incentive program, which provided only cash awards, the LTIP provides us with the flexibility to grant a wide variety of cash and equity or equity-based awards. During 2014, our board of directors granted equity awards under the LTIP to our Named Executive Officers on two separate occasions.

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First, in March of 2014, our board of directors granted a special one-time award consisting of fully vested units and time-based phantom unit awards to certain of our key employees including the Named Executive Officers to compensate them for the additional responsibility and dedication required on their part to successfully launch our initial public offering. Time-based phantom awards vest 50% on the first anniversary of the award and remaining 50% on the second anniversary of the award. The number and grant date fair value of these awards ($20.16 per unit) are included in the table below:

Name	Vested Units Awarded	Time-Based Phantom Units Awarded	Grant Date Fair Value (1)
David C. Glendon	2,894	5,787	$ 175,009
Gary A. Rinaldi	2,894	5,787	$ 175,009
Thomas F. Flaherty	993	0	$ 20,019
John W. Moore	1,654	3,307	$ 100,014
Joseph S. Smith	993	1,984	$ 60,016

(1) The value of vested unit awards and the time-based performance units is based on the grant date fair value of those awards, as calculated pursuant to FASB ASC Topic 718.

Over the course of 2014 Mr. Glendon and our board of directors worked with Meridian to develop a new long term incentive compensation program. After reviewing data provided by Meridian, including, but not limited to equity grant practices of companies with which we compete and considering best practices in executive compensation for publicly traded companies, our board of directors decided that the new long term incentive program should be comprised of an annual award of unit settled, performance-based phantom units that vest based on total unitholder return and relative unitholder return over a pre-established performance period. The board of directors established a total unitholder return threshold to ensure that our unitholders receive a minimum level of return prior to any payment under the long term incentive program, irrespective of how we perform as compared to our peers. They utilized relative unitholder return as the performance criterion to determine the magnitude of the vesting because it provides a relative comparison of our performance against an industry peer group.

In July of 2014 the board of directors granted a target number of phantom performance awards, at fair value of $36.8825 per unit, to each of our Named Executive Officers as follows:

Name	Target Number of Units Granted	Grant Date Fair Value (1)
David C. Glendon	28,000	$ 1,032,710
Gary A. Rinaldi	28,000	$ 1,032,710
Thomas F. Flaherty	7,000	$ 258,178
John W. Moore	7,000	$ 258,178
Joseph S. Smith	7,000	$ 258,178

(1) The value of the phantom performance awards is based on the grant date fair value of those common units, as calculated pursuant to FASB ASC Topic 718.

These awards are settled in stock upon vesting and include a tandem distribution equivalent right, which will be paid upon the settlement of the underlying phantom unit. Before the 2014 phantom unit awards are eligible to vest, our average total unitholder return for the relevant performance period must be at least 3%. If we fail to meet this total unitholder return threshold, the award may still be eligible to vest if the threshold is met over a subsequent rolling 36 month period. Assuming this total unitholder return threshold is met, the 2014 phantom units vest in three tranches, each subject to relative unitholder return performance during the one, two or three year performance period beginning January 1, 2014, respectively. 25% of the target phantom units granted to the Named Executive Officers in 2014 are eligible to vest in each of the first two tranches while 50% of the target number granted are eligible to vest in the third tranche. Our board of directors used this multi-tranche approach for the first annual awards under the new long term incentive program as a transitional tool but expects that future phantom unit awards will be granted with a three-year   cliff vesting   performance period rather than multiple tranches, each with its own performance period. As our relative unitholder return percentile increases as compared to our peers so does the number of phantom units that vest for that performance period, as illustrated in the chart below.

Relative Unitholder Return for Performance Period	**Percentage of Target Phantom Units in Tranche that Vest**
> 30^{th} Percentile	0%
30^{th} Percentile	50%
50^{th} Percentile	100%
90^{th} Percentile	200%

If our relative unitholder return for a performance period falls between the percentiles enumerated above, then the number of phantom units that vest will be calculated using straight line interpolation.

Our board of directors selected the industry peer group for the 2014 phantom units after carefully reviewing information provided by Meridian about including market capitalization, revenues, and business structure of certain companies our industry of selected peers. The board of directors also considered to what extent we directly or indirectly compete with each company in our various market segments. The industry peer group selected by the board of directors for the 2014 phantom unit awards is as follows:

APU - AmeriGas Partners LP	SPH - Suburban Propane Partners, L.P.	MMP - Magellan Midstream Partners LP	TLP - Transmontaigne Partners L.P.
FGP - Ferrellgas Partners LP	BPL - Buckeye Partners, L.P.	NS - NuStar Energy L.P.	ARCX - Arc Logistics Partners LP
GLP - Global Partners LP	HEP - Holly Energy Partners L.P	SUSP - Susser Petroleum Partners LP	WPT - World Point Terminals, LP
NGL - NGL Energy Partners LP	LGP - Lehigh Gas Partners LP	SXL - Sunoco Logistics Partners L.P.	BKEP - Blueknight Energy Partners, L.P.
SGU - Star Gas Partners, L.P.	MMLP - Martin Midstream Partners LP	TLLP - Tesoro Logistics LP	

If during any performance period, any of the companies in the industry peer group cease to exist, cease to be publicly traded, or become inappropriate as our peers due to a material merger or acquisition, as determined by our board of directors, then the company will be removed and the relative unitholder return calculation will be performed using all of the remaining peer companies.

The performance period for the first tranche of the 2014 phantom unit awards ended on December 31, 2014. Our performance for the first performance period generated total unitholder returns of 40.55% which surpassed the total unitholder threshold and put us in the 95^{th} percentile as compared to our industry peer group, resulting in a the vesting and settlement of phantom units equal to 200% of the first tranche of the 2014 phantom units. Upon vesting each of the Named Executive Officers received common units as follows: Mr. Glendon 14,000 units Mr. Rinaldi 14,000 units, Mr. Flaherty 3,500 units, Mr. Smith 3,500 units, and Mr. Moore 3,500 units. All vested awards were net settled.

Historic Long Term Incentive Program Payments in 2014

Under our historic long term incentive program we granted cash awards that paid out in one-third increments in March of each of the three years following the fiscal year for which the award was earned. The second and third payments are contingent upon (i) our earning at least the minimum acceptable threshold return (as described in more detail in our Form 10-K filed for our fiscal year ended December 31, 2013) for each of those years, (ii) the participant continuing to be employed by us on each of the payment dates, and (iii) our discretionary determination each year that such payments should be made based on company-wide as well as individual performance. In light of our implementation of our new annual and long term incentive compensation programs, no awards under this predecessor long term incentive program were granted in 2014. However, because of the three-year payment schedule associated with these awards, amounts with respect to awards granted in prior years were paid during 2014, and will continue to be paid in 2015 and 2016. Specifically, in 2013, our performance generated an aggregate bonus pool equal to $1,978,500 to be paid out in three equal annual installments of $659,500 per year contingent upon the factors enumerated above. The first payment was made in March of 2014 and the second payment was approved by the board of directors and paid in March 2015. In 2012, our performance generated an aggregate bonus pool equal to $927,000 to be paid out in three equal annual installments of $309,000 per year contingent upon the factors enumerated above. The initial payment was made in March 2013, the second payment was made in March of 2014, and the third and final payment was approved by the board of directors and paid in March 2015. The value of all amounts paid under this predecessor long term incentive program are reported in the Bonus column of the Summary Compensation Table.

Severance and Change in Control Benefits

The Named Executive Officers did not have agreements with us that contained severance provisions or change in control payment provisions during the 2014 fiscal year. However, we have a general practice of paying severance to certain of our employees in the event they are terminated by us without cause and they agree to sign a release. The severance historically provided to executives, such as the Named Executive Officers, serving at the Vice President level and above consists of the following: (i) 12 months of severance, (ii) six months of outplacement support, and (iii) health and dental insurance for 12 months at the same cost to the individual as they paid during their employment with us.

We believe that the severance practices we have followed with regard to certain employees in the past have created important retention tools for us, as post-termination payments have allowed employees to leave our employment with value in the event of certain terminations of employment that were beyond their control. As a general matter, post-termination payments allow management to focus their attention and energy on making objective business decisions that are in the best interest of the company without allowing personal considerations to affect the decision-making process. Additionally, executive officers at other companies in our industry and the general market in which we compete for executive talent commonly provide post-termination payments, and we have consistently provided this benefit to certain executives in order to remain competitive in attracting and retaining skilled professionals in our industry.

Other Benefits

Health and Welfare Benefits

All of our regular scheduled full-time employees, including our Named Executive Officers, receive the same health and welfare benefits. The benefits include group health, vision, and dental insurance coverage; participation in our 401(k) and defined contribution pension plan; short and long term disability insurance and life insurance coverage; participation in our flexible spending plan; and tuition assistance. The health and dental plans require employee contributions toward the cost of premiums. We provide short and long term disability as well as basic life insurance at no cost to our employees. Employees may also elect additional life insurance coverage at their own expense.

Retirement Benefits

We provide all employees who were hired prior to January 1, 1991, who were scheduled to work at least 30 hours per week, and who met certain age and service requirements with the opportunity to participate in our retiree health plan. The obligation for premiums under the retiree health plan is shared by both us and the participants and our contributions to such premiums are capped. The retiree health plan does not provide dental benefits. Because Mr. Flaherty is the only Named Executive Officer that was employed by our predecessor prior to January 1, 1991, he is the only Named Executive Officer who may be eligible to participate in our retiree health plan. We also provide our employees with the opportunity to receive post-retirement life insurance on a non-discriminatory basis so long as certain age and service requirements are met. We have historically provided all eligible employees with a retirement program that consisted of two separate plans. All retirement plans discussed below are sponsored and administered by Axel Johnson.

Defined Benefit and Defined Contribution Plans

The Axel Johnson Inc. Retirement Plan, or the DB Plan, is a defined benefit pension plan. The DB Plan was discontinued as of December 31, 2003 and benefits were frozen as of that date with immediate vesting for all active participants in the plan at their then-accrued benefit level. The Axel Johnson Inc. Retirement Restoration Plan, or the RRP, is a related unfunded supplemental plan that provides benefits to employees participating in the DB Plan to the extent benefits cannot be paid from the DB Plan due to legal limitations on the amounts paid under qualified plans set forth in the Internal Revenue Code. In general, the RRP provides benefits for DB Plan participants whose benefits would be limited or whose allowable DB Plan compensation would be limited. As with the DB Plan, benefits under the RRP were frozen as of December 31, 2003. In place of the DB Plan, we implemented a new defined contribution plan, or the DC Plan. The DC Plan was implemented on January 1, 2004. We make all contributions under the DC Plan and participants are not allowed to make contributions. A defined contribution plan specifies the amounts the company will contribute to the plan, but investment decisions and the market risk of those decisions are the obligation of the participant. We contribute an amount equal to 5% of all eligible compensation (including base pay, annual bonus, overtime and commissions) each month to the plan into accounts for every eligible employee, including the Named Executive Officers. Up to an additional 8% is contributed for employees with certain levels of service who participated in the DB Plan when it was frozen and were close to retirement age. This additional contribution is intended to help those employees with a shorter earnings horizon, as they had little time to adjust their financial retirement planning following our decision to freeze the DB Plan. Full-time employees or part-time employees who are regularly scheduled to work more than 1,000 hours annually are eligible to participate. Participating employees are immediately 100% vested in all contributions under the DC Plan.

401(k) Thrift Plan

The second effective retirement plan is a 401(k) thrift plan. All employees who are scheduled to work more than 1,000 hours per year, including the Named Executive Officers, are allowed to contribute their own funds to their 401(k) account and we have historically made certain matching contributions. Employees can contribute between 2% and 70% of their pay (base pay, annual bonus, overtime pay, and commissions) on a pre-tax basis and/or an after-tax basis; however, combined pre-tax and after-tax contributions cannot exceed 70% of pay. The amounts that can be contributed are also subject to the annual limitations imposed by federal tax law. The company will match 60% of the first 6% of pay that an employee contributes to a pre-tax or Roth Plan. Participating employees are immediately 100% vested in all contributions including employee and company contributions as well as any earnings of the plan.

Automobiles and Auto Allowances

We provide cars to employees based on their job requirements, such as the amount of travel that is necessary in order for the executive to properly perform his job duties. Those employees who are eligible to receive a car benefit may elect whether to receive the use of a company car or a cash auto allowance. In 2014, two Named Executive Officers were eligible to receive this benefit; Messrs. Flaherty and Moore (both of whom elected to receive the auto allowance).

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Risk Assessment

The board of directors has reviewed our compensation policies as generally applicable to the employees of our general partner and believes that such policies do not encourage excessive and unnecessary risk-taking, and that the level of risk that they do encourage is not reasonably likely to have a material adverse effect on us. Each time a new compensation policy or program is implemented we consider any risks that may be created by its implementation and work to design the program so as to minimize such risks. In addition, we continually reevaluate the effectiveness of our compensation programs, including an evaluation of the incentives such programs create and how we can minimize or eliminate incentives that may create risk for us.

Our compensation policies and practices are centrally designed and administered, and are substantially identical between our business divisions, except in cases such as commission arrangements which have been tailored to encourage specific sales behavior. In addition, we believe the following specific factors, in particular, reduce the likelihood of excessive risk-taking:

- Our overall compensation levels are competitive with the market.

- Our compensation mix is balanced among fixed components like salary and benefits, as well as annual incentives that reward overall company and individual performance.

- Our new long term equity incentive program is tied to total unitholder return and relative unitholder return over a period of multiple years, with units paid out at the end of the applicable performance period if the pre-established goals are met. This program was designed to encourage executives to focus on unitholder interests over the longer term. In contrast, the annual incentive bonus focuses on distributable cash flow over the shorter term. The combination of both programs appropriately focuses our employees on both our short and longer term performance. The use of multiple performance metrics across programs also means that our executives are not singularly focused on one metric at the exclusion of other important performance goals.

- The board of directors of our general partner has retained an appropriate level of discretion to reduce annual incentive bonus payments if it determines that such adjustments would be appropriate based on our interests and the interests of our unitholders.

Although a significant portion of the compensation provided to Named Executive Officers is performance-based, we believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees) because these programs are designed to encourage employees to remain focused on both our short and long term operational and financial goals. We set performance goals that we believe are reasonable in light of our past performance and market conditions. At the end of each year, we review the performance of every employee as part of an annual performance review that involves several levels of management oversight. The results of those performance reviews, in addition to our short and long term performance, become a major factor in determining what incentives each employee will receive.

A portion of the performance-based, variable compensation we provide is comprised of long term incentives in the form of awards that are subject to non-payment if the organization does not achieve a minimum distributable cash flow or total and relative unitholder return. As such, executives are less likely to take unreasonable risks. Our performance-based incentives, assuming achievement of at least a minimum distributable cash flow and total unitholder return, do provide payouts of some compensation at levels below full target achievement, in lieu of an all or nothing approach.

Additionally, we have a Chief Risk Officer who chairs a Risk Management Committee comprised of several members of management and a representative of our sponsor, that is responsible for reviewing all policies and procedures which could encourage risk taking. In addition to our internal reporting structure, the Chief Risk Officer has a direct reporting relationship to the board of directors and has the authority to review all aspects of our business to ensure that employees are not encouraged to take unnecessary or inappropriate risks.

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Summary Compensation Table for Years Ended December 31, 2014

The table below summarizes the total compensation earned by or paid to our Named Executive Officers in fiscal year 2014.

Name and Title	Year	Salary ($)(1)	Bonus (2)	Stock Awards (3)($)	Change in Pension Value Non-Qualified Deferred Compensation Earnings (4)($)	All Other Compensation (6)($)	Total ($)
David C. Glendon	2014	$ 350,000	$ 717,000	$ 1,891,870	N/A	$ 22,425	$ 2,981,295
President and Chief	2013	$ 350,000	$ 802,000		N/A	$ 22,259	$ 1,174,259
Executive Officer	2012	$ 350,000	$ 486,500		N/A	$ 21,550	$ 858,050
Gary A. Rinaldi	2014	$ 350,000	$ 717,000	$ 1,891,870	N/A	$ 22,525	$ 2,981,395
Senior Vice President,	2013	$ 350,000	$ 802,000		N/A	$ 22,309	$ 1,174,309
Chief Operating Officer and Chief Financial Officer	2012	$ 350,000	$ 486,500		N/A	$ 21,600	$ 858,100
Thomas F. Flaherty	2014	$ 251,960	$ 249,878	$ 581,637	$ 178,199	$ 47,335	$ 1,309,009
Vice President, Refined	2013	$ 247,545	$ 270,000		(5)	$ 47,063	$ 564,608
Products	2012	$ 244,250	$ 162,000		$ 98,228	$ 45,843	$ 550,321
John W. Moore	2014	$ 245,457	$ 239,977	$ 578,878	$ 33,470	$ 29,268	$ 1,127,050
Vice President, Chief Accounting Officer	2013	$ 241,156	$ 265,000		(5)	$ 29,182	$ 535,338
Joseph S. Smith	2014	$ 237,106	$ 238,893	$ 577,502	$ 14,175	$ 22,425	$ 1,090,101
Vice President, Business	2013	$ 232,086	$ 264,000		(5)	$ 21,959	$ 518,045
Development	2012	$ 228,998	$ 157,000		$ 7,535	$ 20,794	$ 414,327

(1) Amounts in this column reflect all compensation earned by the Named Executive Officers during the 2014 fiscal year as base salary. Prior to April 2014, the base salaries for Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith were $350,000, $350,000, $248,206, $241,800, and $232,707, respectively. After April 2014 the base salaries for Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith were as follows: $350,000, $350,000, $253,170, $246,636, and $238,524, respectively.

(2) Amounts in this column reflect the amount of (i) the annual cash bonus award for 2014 in which Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith received $525,000, $525,000, $189,878, $184,977 and $178,893 respectively, (ii) the third (and final) payment under the 2012 LTIP award in which Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith received $62,000, $62,000, $20,000, $15,000 and $20,000 respectively, and (iii) and the second payment under the 2013 LTIP award in which Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith received $130,000, $130,000, $40,000, $40,000 and $40,000 respectively.

(3)

Amounts in this column reflect the grant date fair value of the (i) vested common units granted March 31, 2014 (ii) time based phantom awards granted March 31, 2014, (iii) performance based phantom awards and (iv) units issued pursuant to the 2014 annual incentive bonus program, in each case computed in accordance with FASB ASC Topic 718, disregarding estimated forfeitures. The values of the performance-based phantom units at the grant date assuming that the highest level of performance conditions will be achieved for Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith are as follows: $2,065,420, $2,065,420, $516,355, $516,355 and $516,355, respectively.

(4) Amounts in this column represent the actuarial increase, if any, in the present value of benefits under the DB Plan and the RRP determined by using interest rate and mortality rate assumptions consistent with those used in the Pension Benefits table. Messrs. Glendon and Rinaldi are not participants in these plans. Negative values are not reported in this column and are instead indicated by use of a dash. This column was

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inadvertently excluded from prior filings but has been included for each of 2012, 2013, and 2014 in this filing and the figures in the Total column have been updated for prior years to reflect this change.

(5) For fiscal year 2013 there was an aggregate loss of $43,306, $8,890 and $3,585 in the present value of accumulated benefits for Messrs. Flaherty, Moore, and Smith, respectively, under the DB Plan and RRP.

(6) Amounts in this column reflect, amongst other items, (i) a 401(k) plan matching contribution to Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith in the amounts of $9,360, $9,360, $9,270, $9,003, and $9,360, respectively; (ii) our contribution to the DC Plan for Messrs. Glendon, Rinaldi, Flaherty, Moore and Smith in the amounts of $13,000, $13,000, $26,000, $13,000, and $13,000, respectively; (iii) Messrs. Flaherty s and Moore s car allowance in the amount of $12,000 and $7,200 respectively for the 2014 year. Mr. Rinaldi also received a wellness incentive in the amount of $100. Although we typically make a contribution to the DC Plan equal to 5% of each Named Executive Officer s base pay, we make a supplemental contribution of an additional 5% for Mr. Flaherty, and as such the amount of his DC Plan contribution is double that of the other Named Executive Officers; and (iv) each Named Executive Officer received $65 as the result of the medical loss rebate paid by CIGNA, as required by the National Healthcare Act.

Grants of Plan-Based Awards

The Grants of Plan-Based Awards Table sets forth information regarding the vested common units and time based phantom unit awards granted in March of 2014 in connection with our initial public offering, performance based phantom units granted in July of 2014, and common units issued pursuant to the 2014 annual incentive bonus program, in each case pursuant to our LTIP.

		Estimated Future Payouts Under Equity Incentive Plan Awards (1)			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name (a)	**Grant Date (#)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**(#)**	**($)(5)**
David Glendon	3/31/2014				2,894 (2)	$ 58,343
President and Chief Executive	3/31/2014				5,787 (3)	$ 116,666
Officer	7/11/2014	14,000	28,000	56,000		$ 1,032,710
	3/3/2015				27,811 (4)	$ 684,151
Gary Rinaldi	3/31/2014				2,894 (2)	$ 58,343
Senior Vice President, Chief	3/31/2014				5,787 (3)	$ 116,666
Operating Officer and Chief	7/11/2014	14,000	28,000	56,000		$ 1,032,710
Financial Officer	3/3/2015				27,811 (4)	$ 684,151
Thomas Flaherty	3/31/2014				993 (2)	$ 20,019
Vice President, Refined Products	7/11/2014	3,500	7,000	14,000		$ 258,178
	3/3/2015				12,335 (4)	$ 303,441
John Moore	3/31/2014				1,654 (2)	$ 33,345
Vice President, Chief Accounting	3/31/2014				3,307 (3)	$ 66,669
Officer and Controller	7/11/2014	3,500	7,000	14,000		$ 258,178
	3/3/2015				8,971 (4)	$ 220,687

Joseph Smith	3/31/2014				993 (2)	$ 20,019
Vice President, Business	3/31/2014				1,984 (3)	$ 39,997
Development	7/11/2014	3,500	7,000	14,000		$ 258,178
	3/3/2015				10,541 (4)	$ 259,309

(1) Amounts shown in the Estimated Future Payouts Under Equity Incentive Plans columns represent the threshold, target and maximum settlement levels with respect to the performance based phantom unit awards settled in our common units and granted to our Named Executive Officers pursuant to our LTIP.

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(2) These amounts represent vested common units pursuant to our LTIP.
(3) These amounts represent time based phantom awards that are settled in our common units pursuant to our LTIP.
(4) These amounts represent common units issued pursuant to the 2014 annual incentive bonus program pursuant to our LTIP.
(5) The amounts in this column reflect the aggregate grant date fair value of awards made to our Named Executive Officers in 2014 computed in accordance with FASB ASC Topic 718, disregarding estimated forfeitures. For a discussion of the valuation assumptions, see Note 21 Equity-Based Compensation of the Notes to Consolidated Financial Statements included below.

Outstanding Equity Awards at Fiscal Year-End

The following table reflects the total number of outstanding time and performance based phantom units held by our Named Executive Officers as of December 31, 2014, assuming a market value of $23.45 per common unit (the closing stock price of our common units on December 31, 2014).

	Stock Awards			
Name (a)	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or other Rights That Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or other Rights That Have Not Vested ($)**
David Glendon	5,787 (1)	$ 135,705		
President and Chief Executive Officer	14,000 (2)	$ 328,300	42,000 (3)	$ 984,900
Gary Rinaldi	5,787 (1)	$ 135,705		
Senior Vice President, Chief Operating Officer and Chief Financial Officer	14,000 (2)	$ 328,300	42,000 (3)	$ 984,900
Thomas Flaherty	3,500 (2)	$ 82,075		
Vice President, Refined Products			10,500 (3)	$ 246,225
John Moore	3,307 (1)	$ 77,549		
Vice President, Chief Accounting Officer and Controller	3,500 (2)	$ 82,075	10,500 (3)	$ 246,225

Joseph Smith	1,984 (1)	$ 46,525			
Vice President, Business Development	3,500 (2)	$ 82,075	10,500 (3)	$	246,225

(1) These are time based phantom unit awards that are settled in our common units upon vesting. These awards will vest with respect to 50% on the first anniversary of the award (March 2015) and remaining 50% on the second anniversary of the award (March 2016). These awards contain distribution equivalent rights that are paid out to the phantom unit holders at the same time as such distributions are paid to our unitholders generally.

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(2) These awards represent the number of common units deliverable to each of our Named Executive Officers as a result of the vesting of the first tranche of the performance based phantom unit awards granted in July of 2014. These amounts represent the actual number of our common units earned pursuant to the terms of the awards for the performance period from January 1, 2014 through December 31, 2014, based on our total unitholder return and relative total unitholder return during that period. This tranche vested at 200% of target. Because we achieved our maximum performance goals for the 2014 performance period effective as of December 31, 2014 these awards were no longer considered equity incentive plan awards as of that date. The awards are enumerated in this column because each of our Named Executive Officers must remain employed with us through the date of settlement of the awards or such awards will be forfeited. As such, the awards were not fully vested as of December 31, 2014.

(3) These figures represent the maximum number of unvested performance based phantom units granted in July of 2014 (not including those with a performance period ending December 31, 2014, which are reported in column (g)). The awards are settled in our common units upon vesting. One third of these awards vest based upon total unitholder return and relative total unitholder return during a performance period from January 1, 2014 through December 31, 2015. Two thirds of these awards vest based on the same metrics with respect to a performance period from January 1, 2014 through December 31, 2016. These awards contain distribution equivalent rights that are paid out to the phantom unit holders at the time of settlement of the underlying phantom unit in the same form (cash or common units) as was delivered to our common unitholders at the time of the distribution.

Option Exercises and Stock Vested

None of the time or performance based phantom units granted to our Named Executive Officers under our LTIP vested during the 2014 fiscal year. We have not granted any stock options or stock appreciation rights under our LTIP or otherwise.

Pension Benefits

The following table summarizes the benefits that our Named Executive Officers have accrued under the DB Plan and the RRP in fiscal year 2014.

Name	Plan Name	Number of Years Credited Service (#)(1)(2)	Present Value of Accumulated Benefit ($)(3)	Payments During 2014 Fiscal Year ($)
David C. Glendon	Axel Johnson Inc. Retirement Plan			
President and Chief Executive Officer	Axel Johnson Inc. Retirement Restoration Plan			
Gary A. Rinaldi	Axel Johnson Inc. Retirement Plan			

Senior Vice President, Chief Operating Officer and Chief Financial Officer	Axel Johnson Inc. Retirement Restoration Plan			
Thomas F. Flaherty	Axel Johnson Inc. Retirement Plan	20.42	$	727,824
Vice President, Refined Products	Axel Johnson Inc. Retirement Restoration Plan	20.42	$	190,847

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Name	Plan Name	Number of Years Credited Service (#)(1)(2)	Present Value of Accumulated Benefit ($)(3)	Payments During 2014 Fiscal Year ($)
John W. Moore	Axel Johnson Inc. Retirement Plan	5.50	$ 151,743	
Vice President, Chief Accounting Officer and Controller	Axel Johnson Inc. Retirement Restoration Plan	5.50	$ 6,514	
Joseph S. Smith	Axel Johnson Inc. Retirement Plan	2.17	$ 66,424	
Vice President, Business Development	Axel Johnson Inc. Retirement Restoration Plan	2.17	$ 3,618	

(1) Amounts in this column represent the number of years of credited service rounded to the nearest month and were frozen as of December 31, 2003.

(2) Messrs. Glendon and Rinaldi were not eligible to participate in the DB Plan or the RRP since they were hired after January 1, 2003.

(3) Amounts in this column represent the actuarial present value of each Named Executive Officer s accumulated benefit under the DB Plan and the RRP as of December 31, 2014. In quantifying the present value of the accumulated benefit indicated above, we used the same assumptions used for financial reporting purposes under GAAP, except that retirement age was assumed to be the earliest time at which a participant may retire under the plan without any benefit reduction due to age. The material assumptions were as follows: (i) an estimated discount rate of 4.19% for the Axel Johnson Inc. Retirement Plan and 4.08% for the Axel Johnson Inc. Retirement Restoration Plan, (ii) the RP-2014 annuitant table and the MP-2014 mortality improvement scale and (iii) expected long-term rate of return on plan assets of 6.50%.

The information in the table above relates to our Named Executive Officers participation in the DB Plan and the RRP. The DB Plan and RRP were available to employees of subsidiaries of Axel Johnson who were scheduled to work at least 20 hours per week (or 1,000 hours per year), were not temporary or leased employees, and who satisfied a one-year waiting period. The DB Plan and the RRP were both discontinued as of December 31, 2003 and benefits were frozen (*i.e.* , participants will experience no increase attributable to years of service or change in eligible earnings) as of that date with immediate vesting of all active participants in the plan at their then-accrued benefit level. We implemented the DC Plan on January 1, 2004 to replace the DB Plan.

The benefits paid under the RRP are determined by calculating the benefits payable from the DB Plan as if there were no legal limitations, and then subtracting the actual benefits payable from the DB Plan. The DB Plan benefit paid to participants is based on a formula using the employee s final average compensation, credited service, and social security covered compensation, each of which is calculated on the earlier of December 31, 2003 or the date of retirement or termination. The annual annuity benefit payable at retirement under the DB Plan is calculated as follows:

1.1% of final average compensation	x	Credited service (up to 40 years, rounded to the nearest month)	+	0.4% of final average compensation in excess of social security covered compensation	x	Credited service (up to 35 years, rounded to the nearest month)

A participant s final average compensation is calculated by taking the average of a participant s highest pensionable earnings in any 60-consecutive-month period before the earlier of December 31, 2003, termination, or retirement. Pensionable earnings include regular wages or salary, overtime, shift differentials, short-term incentive payment, and commissions. Employees generally received one year of credited service for each

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calendar year in which the employee performed 1,000 hours or more of service. Social security wage covered compensation is typically the average of the social security wage bases for the 35-year period ending with the last day of the calendar year in which a participant is eligible for unreduced social security retirement benefits. However, because each participant s benefit had to be calculated as of December 31, 2003 when the DB Plan was frozen, the calculation was based on the social security covered compensation in effect as of the earlier of 2003 or the year the participant terminated employment. If the calculation date was prior to social security retirement age, the social security covered compensation is calculated assuming the wage base for all future years is equal to the then-current year s wage base.

The normal retirement age is 65 years old. A participant may qualify for early retirement if, when the participant leaves the company, that participant is at least 55 years old and has at least ten years of total credited service. As of December 31, 2014, Messrs. Flaherty and Moore were the only Named Executive Officers eligible for early retirement; no Named Executive Officer was eligible for normal retirement. A participant can receive full DB Plan benefits as early as the participant s 62nd birthday. If a participant elects to receive a benefit prior to age 62, the benefit would be reduced by 5/12% for each month (5% per year) that the benefit starts before age 62. If a participant ceases to be employed by us prior to age 55 or prior to accumulating ten years of credited service, the participant may elect to receive the deferred vested benefit beginning as early as age 55. However, if the participant elects to receive the benefit before the normal retirement date, such benefit will be reduced by 1/2 % for each month (6% per year) that payment of the benefit starts before the normal retirement date.

Payment methods are determined based on the participant s marital status and/or election. The normal form of payment for a single participant is a life income annuity; for a married participant, it is a 50% joint and survivor annuity. Optional payment methods include a contingent annuitant option at 50%, 75% or 100%; a life income option; a 120 month certain and life income option; or a Social Security adjustment option. If a married participant dies, his or her spouse is entitled to survivor benefits. The time and form of payment under the RRP is typically identical to the time and form of payment under the DB Plan or may be in the form of an actuarially equivalent lump sum paid at the time benefits commence under the DB Plan.

Potential Payments Upon Termination or a Change in Control

The Named Executive Officers did not have agreements with us that contained severance provisions or change in control payment provisions during the 2014 fiscal year. However, we have a general practice of paying severance to certain of our employees in the event they are terminated by us without cause and they agree to sign a release. A termination without cause has historically been determined on a case by case basis rather than by applying any one definition or a specific set of events to each employee. The severance historically provided to executives, such as the Named Executive Officers, serving at the Vice President level and above consists of the following: (i) 12 months of severance, (ii) 6 months of outplacement support and (iii) health and dental insurance for 12 months at the same cost to the individual as they paid during their employment with us. The table below shows our best estimate as to the amounts that each of the Named Executive Officers would have received on December 31, 2014, if the Board had determined the individual s employment was terminated without cause on that date.

Name	Cash Severance	Outplacement Support (1)	Health and Dental (2)	Total Severance Benefits
David C. Glendon	$ 350,000	$ 6,000	$ 16,072	$ 372,072
President and Chief Executive Officer				

Gary A. Rinaldi Senior Vice President, Chief Operating Officer and Chief Financial Officer	$	350,000	$	6,000	$	11,806	$	367,806
Thomas F. Flaherty Vice President, Refined Products	$	253,170	$	6,000	$	16,072	$	275,242

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Name	Cash Severance	Outplacement Support (1)	Health and Dental (2)	Total Severance Benefits
John W. Moore Vice President, Chief Accountant and Controller	$ 246,636	$ 6,000	$ 16,062	$ 268,699
Joseph S. Smith Vice President, Business Development	$ 238,524	$ 6,000	$ 16,062	$ 260,587

(1) Amounts in this column reflect the estimated cost to us of providing outplacement services to the Named Executive Officers over a six-month period; however, such services would be provided by an outside vendor and could vary based on the individual needs of each executive.

(2) Amounts in this column reflect the value of continued health and dental benefits based on the value of the benefits received by each individual as of December 31, 2014.

In addition to the amounts reported above, the time-based performance awards granted on March 31, 2014 provide for full acceleration of vesting of any unvested time-based performance awards granted thereunder in the event of (i) the Named Executive Officer s termination of employment by reason of death or Disability (as defined below) or (ii) a Change of Control (as defined below). In the event either such event occurred on December 31, 2014, the value of the acceleration of vesting of the time-based performance awards received by each of the Named Executive Officers would be as follows: Mr. Glendon $135,705, Mr. Rinaldi $135,705, Mr. Moore $77,549, and Mr. Smith $46,525. In calculating these amounts we assumed that the price per share of our units was the closing market price as of December 31, 2014, which was $23.45.

As used in the time-based phantom unit award agreement, Disability means that the Named Executive Officer is unable to engage in substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

Pursuant to the terms of our LTIP, Change of Control means one or more of the following events: (i) any person or group within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than members of the general partner, the Partnership, or an Affiliate of either the general partner or the Partnership, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the voting power of the voting securities of the general partner or us; (ii) the limited partners of the general partner or of us approve, in one transaction or a series of transactions, a plan of complete liquidation of the general partner or us; (iii) the sale or other disposition by either the general partner or us of all or substantially all of its assets in one or more transactions to any person other than an affiliate; (iv) the general partner or an affiliate of the general partner or us ceases to be our general partner; (v) any other event specified as a Change of Control in an applicable award agreement. Notwithstanding the above, with respect to an award that is subject to Section 409A of the Code, a Change of Control will not occur unless that Change of Control also constitutes a change in the ownership of a corporation, a change in the effective control of a corporation, or a change in the ownership of a substantial portion of a corporation s assets, in each case, within the meaning of 1.409A-3(i)(5) of the Treasury Regulations, as applied to non-corporate entities.

The Named Executive Officers must remain employed through the date of settlement of a performance-based phantom unit in order to receive delivery of common units thereunder. If a Named Executive Officer ceases to provide services to us for any reason prior to settlement of performance-based phantom units, that officer will forfeit their rights to any payment with respect to those awards.

The above descriptions of the phantom unit award agreements and our LTIP do not purport to be complete and are qualified in their entirety by reference to the full text of the phantom unit agreements and the LTIP, which are filed as Exhibit 10.6, 10.7 and 10.10 hereto.

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2014 DIRECTOR COMPENSATION

We use a combination of cash and equity compensation to attract and retain qualified candidates to serve as directors. In setting director compensation, we consider the time commitment directors must make in performing their duties, the level of skills required by directors and the market competitiveness of director compensation levels.

Officers, employees or paid consultants and advisors of our general partner or its affiliates (including Axel Johnson Inc. and its affiliates) who also serve as members of the board of directors of the general partner will not receive additional compensation for their service as members of the board. All members of the board not included in the preceding sentence shall be referred to as the non-employee directors . Each non-employee director will receive an annual retainer of $60,000, paid in quarterly installments. Each non-employee director will also receive an annual award, granted within five business days of October 15 of each year, of the number of fully vested common units representing limited partner interests (Common Units) in the Partnership having a grant date fair value of approximately $60,000, subject to the terms and vesting schedules set forth in the applicable grant documents. Further, each non-employee director serving as a chairman or a member of a committee of the board will receive an annual retainer of $10,000 or $5,000, respectively, paid in quarterly installments. Annual cash retainers and grants of Common Units will be pro-rated for directors who join the board mid-year. All directors will receive reimbursement for out-of-pocket expenses associated with attending meetings of the board or committees of the board. Each director will receive liability insurance coverage and be fully indemnified by the Partnership for actions associated with being a director to the fullest extent permitted under Delaware law.

Messrs. Evans and Harper and Ms. Bowman all received the annual grant valued at $60,000 in October 2014 (fully vested). In addition to the director compensation described above, in March 2014, the Board approved the issuance of a special one-time unit award to Messrs. Evans and Harper valued at $20,000 (fully vested).

The table below summarizes the compensation paid to independent directors for the fiscal year ended December 31, 2014.

Name (1)	Fees Earned or Paid in Cash ($)(4)	Unit Awards ($)(5)(6)	Total ($)
Michael D. Milligan (2)			
Ben J. Hennelly (2)			
Robert B. Evans	$ 75,000	$ 80,024	$ 155,024
C. Gregory Harper	$ 75,000	$ 80,024	$ 155,024
Beth A. Bowman (3)	$ 17,500	$ 60,006	$ 77,506

(1) Messrs. Glendon and Rinaldi serve as our Named Executive Officers and are not included in this table because they receive no compensation for their services as directors and the compensation received by Messrs. Glendon and Rinaldi as our Named Executive Officers is shown in the Summary Compensation Table.
(2) Messrs. Milligan and Hennelly, as officers of Axel Johnson, do not receive separate compensation for their services as directors.
(3) Ms. Bowman joined the Board in October 2014.
(4) The amounts in this column reflect the aggregate dollar amount of fees earned or paid in cash including prorated annual retainer fees and chairmanship or membership fees. Mr. Evans served on the Conflicts Committee

(Chairman) and the Audit Committee, and Mr. Harper served on the Audit Committee (Chairman) and Conflicts Committee. Ms. Bowman is a member of the Audit Committee and the Conflicts Committee.

(5) Represents the aggregate grant date fair value computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation Stock Compensation (FASB ASC

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Topic 718). Messrs. Evans and Harper received a special one-time grant valued at $20,000 in March 2014. Messrs. Evans and Harper and Ms. Bowman all received the annual grant valued at $60,000 in October 2014. Please see Note 21 to our Consolidated Financial Statements for assumptions used in valuing our Common Units.

(6) On December 31, 2014, each director held the following aggregate number of outstanding, unvested awards for service as a director: Mr. Evans 2,222 Restricted Units; and Mr. Harper 2,222 Restricted Units.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of common units and subordinated units of Sprague Resources LP that are issued and outstanding as of March 9, 2015 and held by:

each person known by us to be a beneficial owner of more than 5% of our outstanding units, including Sprague Holdings;

each of the directors of and nominees to our general partner s board of directors;

each of the named executive officers of our general partner; and

all of the directors, director nominees and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common and Subordinated Units Beneficially Owned
Sprague Holdings LLC (1)(2)	1,571,970	14.3%	10,071,970	100.0%	55.2%
Sprague International Properties LLC (1)(2)	462,408	4.2%			2.2%
Axel Johnson (2)(3)	2,034,378	18.5%	10,071,970	100.0%	57.4%
Lexa International Corporation (2)(4)	2,034,378	18.5%	10,071,970	100.0%	57.4%
Antonia Ax:son Johnson (2)(5)	2,034,378	18.5%	10,071,970	100.0%	57.4%
Kayne Anderson Capital Advisors (6)	1,844,603	16.8%			8.8%
OppenheimerFunds, Inc. (7)	1,641,488	14.9%			7.8%
Goldman Sachs Asset Management (8)	1,461,634	13.3%			6.9%

Michael D. Milligan	20,000	*	*
David C. Glendon	36,130(9)	*	*
Gary A. Rinaldi	33,896(10)	*	*
Beth A. Bowman	2,661	*	*
Robert B. Evans	6,987	*	*
C. Gregory Harper	6,987	*	*
Ben J. Hennelly			
Sally A. Sarsfield	4,100	*	*
Thomas E. Flaherty	12,039	*	*
John W. Moore	11,729(11)	*	*
Joseph S. Smith	11,728(12)	*	*
All executive officers and directors of our general partner as a group (15 persons)	189,883(13)	1.7%	*

* Represents less than 1%.

(1) The address for this entity is 185 International Drive, Portsmouth, NH 03801.

(2) Common units and subordinated units shown as beneficially owned by Axel Johnson, Lexa International Corporation and Antonia Ax:son Johnson reflect common units and subordinated units owned of record by

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Sprague Holdings and Sprague International Properties LLC, a wholly-owned subsidiary of Sprague Holdings. Sprague Holdings is a wholly-owned subsidiary of Axel Johnson and, as such, Axel Johnson may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings and its subsidiaries, but disclaims such beneficial ownership. Axel Johnson is a wholly-owned subsidiary of Lexa International Corporation and, as such, Lexa International Corporation may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership. Lexa International Corporation, through certain non-U.S. entities, is controlled by Antonia Ax:son Johnson and, as such, Antonia Ax:son Johnson may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership.

(3) The address for this entity is 155 Spring Street, 6th Floor, New York, NY 10012.

(4) The address for this entity is 2410 Old Ivy Road, Suite 300, Charlottesville, VA 22903.

(5) The address for this person is c/o Axel Johnson AB, Villagatan 6, P.O. Box 26008, SE-100 41 Stockholm, Sweden.

(6) The address for this entity is 1800 Avenue of the Stars, Third Floor, Los Angeles, CA 90067. Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have reported that they have shared voting and dispositive power with respect to all of the 1,844,603 common units. Beneficial ownership reported based solely on a Schedule 13G/A filed on February 14, 2015.

(7) The address for this entity is 225 Liberty Street, New York, NY 10281. Oppenheimer Funds, Inc. reports shared voting power and shared dispositive power for 1,641,488 common units. Oppenheimer SteelPath MLP Income Fund, whose address is 6803 S. Tuscon Way, Centennial, CO 80112, reported that they have sole voting power and shared dispositive power with respect to 1,530,958 common units. Oppenheimer Funds, Inc. reported beneficial ownership of 1,641,488 common units which includes 1,530,958 common units beneficially owned by Oppenheimer SteelPath MLP Income Fund. Beneficial ownership reported based solely on a Schedule 13G/A filed on February 9, 2015.

(8) Goldman Sachs Asset Management, L.P., together with GS Investment Strategies, LLC jointly filed by Goldman Sachs Asset Management. The address for this entity is 200 West Street, New York, NY 10282. Goldman Sachs Asset Management has reported that it has shared voting and dispositive power with respect to all of the 1,461,634 common units. Beneficial ownership reported based solely on a Schedule 13G/A filed on February 12, 2015.

(9) Includes 2,894 units that will vest and net settle within 60 days of March 9, 2015.

(10) Includes 2,894 units that will vest and net settle within 60 days of March 9, 2015.

(11) Includes 1,654 units that will vest and net settle within 60 days of March 9, 2015.

(12) Includes 992 units that will vest and net settle within 60 days of March 9, 2015.

(13) The address of each of the executive officers and directors is 185 International Drive, Portsmouth, NH 03801. Except as noted in the footnotes to this table, common units beneficially owned by executive officers and directors consist of units owned by the indicated person. Includes 9,922 units that will vest and net settle within 60 days of March 9, 2015.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following information is reported as of December 31, 2014.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)(1)	Weighted-average exercise price of outstanding options, warrants and rights (b)(2)	Number of Securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	171,784		549,149

(1) Awards in this column represent the total number of all performance-based phantom units granted under our LTIP and outstanding as of December 31, 2014. We have not granted any stock option awards.

(2) The outstanding phantom units do not have an exercise price. As such, there is no weighted average exercise price to report for outstanding awards.

Our only equity compensation plan is the Sprague Resources LP 2013 Long-Term Incentive Plan, also referred to herein as the LTIP . The LTIP was approved by our shareholders prior to our initial public offering but has not been approved by our public shareholders. A description of the material terms of the LTIP is available in our registration statement on Form S-1, last filed on October 15, 2013 under the heading Compensation Discussion and Analysis 2013 Long-Term Incentive Plan.

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Item 13. Certain Relationships, Related Transactions and Director Independence

Distributions and Payments to Sprague Holdings and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to Sprague Holdings and its affiliates in connection with our formation and ongoing operation and distributions and payments that would be made by us if we were to liquidate in accordance with the terms of our partnership agreement. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Formation Stage

The consideration given to Sprague Holdings and its affiliates for the contributions of assets and liabilities to us	1,571,970 common units;
	10,071,970 subordinated units;
	non-economic general partner interest; and
	incentive distribution rights; and

Operational Stage

Distributions of cash to Sprague Holdings and its affiliates	We will generally make cash distributions to common and subordinated unitholders, including Sprague Holdings as the holder of an aggregate of 1,571,970 common units and all of the subordinated units and Sprague International Properties LLC, an indirect, wholly-owned subsidiary of Sprague Holdings, and the holder of 462,408 common units. Our general partner will not receive distributions on its non-economic general partner interest. If distributions exceed the minimum quarterly distribution and other higher target levels, the holders of our incentive distribution rights (currently Sprague Holdings) will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target level. Assuming we have sufficient distributable cash flow to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, Sprague Holdings would receive an annual distribution of approximately $19.2 million on its common and subordinated units and Sprague International Properties LLC would receive an annual distribution of approximately $0.8 million on its common units. If Sprague Holdings elects to reset the target distribution levels, it will be entitled to receive a certain number of common units.

Payments to our general partner and its affiliates	Our general partner will not receive any management fee or other compensation for its management of us, except as set forth in the services agreement entered into in connection with the closing of the IPO. Under the terms of the

	partnership agreement, our general partner and its affiliates will be reimbursed for all expenses incurred on our behalf.
	Pursuant to the terms of the services agreement, our general partner agreed to provide certain general and administrative services and operational services to us, and we agreed to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Neither the partnership agreement nor the services agreement limits the amount that may be reimbursed or paid by us to our general partner or its affiliates. The aggregate amount of reimbursements and fees paid by us to our general partner was \$82.0 million for the period from January 1, 2014 to December 31, 2014.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, the general partner interest and its affiliates incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates

In connection with the completion of our IPO on October 30, 2013, we entered into certain agreements with our sponsor and certain of its affiliates, as described below.

Omnibus Agreement

We entered into an omnibus agreement with Axel Johnson, Sprague Holdings and our general partner that will address the agreement of Axel Johnson to offer to us and to cause its controlled affiliates to offer to us opportunities to acquire certain businesses and assets and the obligation of Sprague Holdings to indemnify us for certain liabilities. This agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to this agreement as could have been obtained from unaffiliated third parties. The omnibus agreement may be terminated (other than with respect to the indemnification provisions) by any party to the agreement in the event that Axel Johnson, directly or indirectly, owns less than 50% of the voting equity of our general partner.

Right of First Refusal

Under the terms of the omnibus agreement, Axel Johnson has agreed, and has caused its controlled affiliates to agree, for so long as Axel Johnson or its controlled affiliates, individually or as part of a group, control our general partner, that if Axel Johnson or any of its controlled affiliates has the opportunity to acquire a controlling interest in any assets or any business having assets that are primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada, then Axel Johnson or its controlled affiliates will offer such acquisition opportunity to us and give us a reasonable opportunity to acquire such assets or business either before Axel Johnson or its controlled affiliates acquire it or promptly after the consummation of such acquisition by Axel Johnson or its controlled affiliates, at a price equal to the purchase price paid or to be paid by Axel Johnson or its controlled affiliates plus any related transactions costs and expenses incurred by Axel Johnson or its controlled affiliates. Our decision to acquire or not acquire any such assets or businesses will require the approval of the conflicts committee of the board of directors of our general partner. Any assets or businesses that we do not acquire pursuant to the right of first refusal may be acquired and operated by Axel Johnson or its controlled affiliates.

This right of first refusal will not apply to:

- Any acquisition of any additional interests in any assets or businesses owned by Axel Johnson or its controlled affiliates at the time of the IPO but not contributed to us in connection with the IPO, including any replacements and natural extensions thereof;

- Any investment in or acquisition of any assets or businesses primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that do not operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada;

- Any investment in or acquisition of a minority non-controlling interest in any assets or businesses primarily engaged in the businesses described above; or

- Any investment in or acquisition of any assets or businesses that Axel Johnson or its controlled affiliates, at the time of the closing of the IPO, are actively seeking to invest in or acquire, or have the right to invest in or acquire.

Right of Negotiation

Under the terms of the omnibus agreement, Axel Johnson has agreed and has caused its controlled affiliates to agree, for so long as Axel Johnson or its controlled affiliates, individually or as part of a group, control our general partner, that if Axel Johnson or any of its controlled affiliates decide to attempt to sell (other than to another controlled affiliate of Axel Johnson) any assets or businesses that are primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada (including its equity interests in Kildair or any successor entities thereof and its interests in any assets or equity interests in any business that, at the time of the IPO, it is actively seeking to invest in or acquire or has the right to invest in or acquire), Axel Johnson or its controlled affiliate will notify us of its desire to sell such assets or businesses and, prior to selling such assets or businesses to a third party, will negotiate with us exclusively and in good faith for a period of 60 days in order to give us an opportunity to enter into definitive documentation for the purchase and sale of such assets or businesses on terms that are mutually acceptable to Axel Johnson or its controlled affiliate and us. If we and Axel Johnson or its controlled affiliate have not entered into a letter of intent or a definitive purchase and sale agreement with respect to such assets or businesses within such 60 days, Axel Johnson or its controlled affiliate will have the right to sell such assets or businesses to a third party following the expiration of such

60 days on any terms that are acceptable to Axel Johnson or its controlled affiliate and such third party. Our decision to acquire or not to acquire assets or businesses pursuant to this right will require the approval of the conflicts committee of the board of directors of our general partner. Our right of negotiation, to the extent it applies to any of Axel Johnson s direct or indirect equity interests in Kildair, any subsidiary of Kildair, or any entity that owns equity interests in Kildair, shall not be applicable to any transfer, assignment, foreclosure, deed-in-lieu of foreclosure, or other disposition of any such equity interests occurring as a result of the exercise of remedies by any lenders to Kildair, any subsidiary of Kildair, or any entity that owns equity interests in Kildair.

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Trade Credit Support

Under the terms of the omnibus agreement, Axel Johnson agreed to continue to provide credit support to us, consistent with past practice, through December 31, 2016, if, and to the extent, such services are necessary in our reasonable judgment. We will agree to use our commercially reasonable efforts to reduce, and eventually eliminate, the need for trade credit support from Axel Johnson.

Indemnification

Under the omnibus agreement, Sprague Holdings will indemnify us for losses attributable to a failure to own any of the equity interests contributed to us in connection with the formation transactions and income taxes attributable to pre-closing operations and the formation transactions.

Services Agreement

The Partnership, Sprague Energy Solutions, Inc. (Sprague Solutions) and Sprague Holdings entered into a services agreement with our general partner pursuant to which our general partner will agree to provide certain general and administrative services and operational services to us and our subsidiaries, Sprague Solutions and Sprague Holdings. Pursuant to the terms of the services agreement, we agreed to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Pursuant to the terms of the services agreement, our general partner will agree to provide the same services to Sprague Solutions and Sprague Holdings, which also agreed to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services.

The services agreement does not limit the amount that may be reimbursed or paid by us to our general partner or its affiliates. The amount of reimbursements and fees paid by us to our general partner was $82.0 million for the period from January 1, 2014 to December 31, 2014.

The initial term of the services agreement is five years, beginning on October 30, 2013. The agreement will automatically renew at the end of the initial term for successive one-year terms until terminated by us or by Sprague Solutions or by giving 180 days prior written notice to our general partner. The agreement will automatically terminate on the date Sprague Resources GP LLC ceases to be our general partner. The provisions of the services agreement that are applicable to Sprague Holdings may be terminated by Sprague Holdings by giving 180 days prior written notice to our general partner, and will automatically terminate on the date on which Sprague Holdings ceases to be our affiliate. The provisions of the services agreement applicable to Sprague Solutions shall automatically terminate on the date on which Sprague Solutions ceases to be a wholly owned direct or indirect subsidiary of us. The services agreement does not limit the ability of the officers and employees of our general partner to provide services to other affiliates of Sprague Holdings or unaffiliated third parties.

The services agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to the agreement as could have been obtained from unaffiliated third parties.

Contribution Agreement

In connection with the IPO, we entered into a contribution, conveyance and assumption agreement, which we refer to as our contribution agreement, with Axel Johnson, Sprague Holdings and certain of its subsidiaries, our general partner, and Sprague Operating Resources LLC under which, among other things, effected the transactions, including the transfer of ownership interest in our initial assets and the issuance by us to our sponsor of common units, subordinated units and the incentive distribution rights, and the use of proceedings related to our IPO.

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Terminal Operating Agreement

We entered into an exclusive terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC, which is a wholly owned subsidiary of Sprague Holdings, or one of its wholly owned subsidiaries, with respect to the terminal in New Bedford, Massachusetts. Pursuant to the terminal operating agreement, we were granted the exclusive use and operation of, and will retain title to all of the refined products stored at, the New Bedford terminal in exchange for a monthly fee of $15,200, subject to adjustment for changes in the Consumer Price Index for the Northeast region. This agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to this agreement as could have been obtained from unaffiliated third parties.

The initial term of the terminal operating agreement is five years, beginning on October 30, 2013. Thereafter, we will have the right to extend the term for five years. Additionally, the terminal operating agreement will terminate upon 60 days written notice from Sprague Holdings or Sprague Massachusetts Properties LLC in the event that Sprague Holdings or Sprague Massachusetts Properties LLC determines that termination is necessary to facilitate the sale or development of the New Bedford terminal. The New Bedford terminal is subject to a purchase and sale agreement pursuant to which a third party may acquire the terminal from Sprague Massachusetts Properties LLC. The acquisition is subject to certain conditions that are beyond the control of Sprague Massachusetts Properties LLC. Subject to those conditions, the acquisition may be consummated on or before January 5, 2016. In the event that such sale is consummated, our terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC will automatically terminate. We will not receive any proceeds from a sale of the New Bedford terminal.

Kildair Acquisition Agreement

On December 9, 2014, pursuant to a Purchase Agreement by and among Sprague Resources ULC, an indirect subsidiary of the Partnership, Sprague International Properties LLC, Sprague Canadian Properties LLC and Axel Johnson Inc., the Partnership indirectly acquired all of the equity interests of Kildair for total consideration of $175.0 million, consisting of (i) $165.0 million in cash (a portion of which was used by Kildair to retire third-party and related party debt) and (ii) 462,408 common units issued by the Partnership having a value equal to $10.0 million. In assessing the Kildair acquisition, the conflicts committee retained a financial advisor; and, after review and evaluation, the conflicts committee approved the Kildair acquisition and the total consideration paid.

Director Independence

The information required by Item 407(a) of Regulation S-K is included in Item 10. Directors, Executive Officers and Corporate Governance above.

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Item 14. Principal Accounting Fees and Services

The Audit Committee has selected Ernst & Young LLP to serve as the Partnership s independent auditor for the fiscal year ending December 31, 2014. The Audit Committee in its discretion may select a different registered public accounting firm at any time during the year if it determines that such a change will be in the best interests of the Partnership and our unitholders.

Audit Fees

The following table presents fees for auditing, tax and related services rendered by Ernst & Young LLP to us for each of the last two fiscal years.

	Fiscal 2014	Fiscal 2013
Audit Fees (1)	$ 2,520,000	$ 1,550,000
Audit-Related Fees		
Tax Fees (2)	325,000	710,000
All Other Fees		
Total	$ 2,845,000	$ 2,260,000

(1) Fees for audit services billed or expected to be billed consisted of the audit of our annual financial statements, reviews of our interim financial statements and services associated with SEC registration statements and other SEC matters.
(2) Fees for tax services billed or expected to be billed consisted of services associated with the SEC registration statements, services related to tax compliance and services related to the review of our partnership Form K-1.

The Audit Committee of the Partnership was formed subsequent to the IPO. Therefore, in considering the nature of services provided by Ernst & Young LLP, for Fiscal 2013 services, the Board of Directors of our General Partner determined that such Fiscal 2014 and 2013 services are compatible with the provisions of independent audit services. The Board of Directors discussed these services with Ernst & Young LLP and our management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Policy for Approval of Audit and Non-Audit Services

Our audit committee charter requires that all services provided by our independent public accountants, both audit and non-audit, must be pre-approved by the audit committee. The pre-approval of audit and non-audit services may be given at any time up to a year before commencement of the specified service.

In determining whether to approve a particular audit or permitted non-audit service, the audit committee will consider, among other things, whether such service is consistent with maintaining the independence of the independent public accountants. The audit committee will also consider whether the independent public accountants are best positioned to provide the most effective and efficient service to us and whether the service might be expected to enhance our ability to manage or control risk or improve audit quality.

All fees paid to Ernst & Young LLP subsequent to the IPO were pre-approved by the audit committee in accordance with this policy.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits The following documents are filed as part of this Annual Report on Form 10-K for the year ended December 31, 2014.

1. Sprague Resources LP Audited Consolidated and Combined Financial Statements:

2. Financial Statement Schedules No schedules are included because the required information is inapplicable or is presented in the Consolidated and Combined Financial Statements or related notes thereto.

3. Exhibits:

The list of exhibits attached to this Annual Report on Form 10-K is incorporated herein by reference.

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

Sprague Resources LP

By: Sprague Resources GP LLC, its general partner

By: /s/ David C. Glendon
David C. Glendon
President, Chief Executive Officer
(On behalf of the registrant, and in his capacity
as principal executive officer)

Date: March 16, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael D. Milligan Michael D. Milligan	Chairman of the Board of Directors	March 16, 2015
/s/ David C. Glendon David C. Glendon	President, Chief Executive Officer and Director (Principal Executive Officer)	March 16, 2015
/s/ Gary A. Rinaldi Gary A. Rinaldi	Senior Vice President, Chief Operating Officer and Chief Financial Officer and Director (Principal Financial Officer and Principal Accounting Officer)	March 16, 2015
/s/ Beth A. Bowman Beth A. Bowman	Director	March 16, 2015
/s/ Robert B. Evans Robert B. Evans	Director	March 16, 2015
/s/ C. Gregory Harper	Director	March 16, 2015

C. Gregory Harper		
/s/ Ben J. Hennelly	Director	March 16, 2015
Ben J. Hennelly		
/s/ Sally A. Sarsfield	Director	March 16, 2015
Sally A. Sarsfield		

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors of Sprague Resources GP and Unitholders of Sprague Resources LP

We have audited the accompanying consolidated balance sheets of Sprague Resources LP (the Partnership) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, comprehensive income (loss), member s/unitholders equity, and cash flows for each of the two years in the period ended December 31, 2014, and the related consolidated statements of operations, comprehensive loss, member s equity, and cash flows of Sprague Operating Resources LLC (the Predecessor) for the year ended December 31, 2012. These financial statements are the responsibility of the Partnership s and Predecessor s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial positions of Sprague Resources LP at December 31, 2014 and 2013 and the consolidated and combined results of its operations and its cash flows for each of the two years in the period ended December 31, 2014, and the consolidated results of Sprague Operating Resources LLC s (the Predecessor) operations and cash flows for the year ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Sprague Resources LP s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New York, New York

March 16, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors of Sprague Resources GP and Unitholders of Sprague Resources LP

We have audited Sprague Resources LP s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Sprague Resources LP s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management s Report on Internal Control Over Financial Reporting, management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Metromedia Gas and Power, Inc., Castle Oil, and Kildair, which are included in the December 31, 2014 consolidated financial statements of Sprague Resources LP and constituted $390.9 million and $47.2 million of total and net assets, respectively, as of December 31, 2014 and $582.5 million and $6.9 million of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Sprague Resources LP also did not include an evaluation of the internal control over financial reporting of Metromedia Gas and Power, Inc., Castle Oil, and Kildair.

In our opinion, Sprague Resources LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Sprague Resources LP (the Partnership) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, comprehensive income (loss), member s/unitholders equity, and cash flows for each of the two years in the period ended December 31, 2014, and the related consolidated statements of operations, comprehensive loss, member s equity, and cash flows of Sprague Operating Resources LLC (the Predecessor) for the year ended December 31, 2012 and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New York, New York

March 16, 2015

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Sprague Resources LP

Consolidated Balance Sheets

(in thousands except units)

	December 31, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 4,080	$ 2,046
Accounts receivable, net	289,424	274,687
Inventories	390,555	437,135
Fair value of derivative assets	229,890	65,098
Deferred income taxes	895	2,207
Other current assets	52,416	31,436
Total current assets	967,260	812,609
Property, plant, and equipment, net	250,126	198,476
Assets held for sale	1,321	
Intangibles, net	27,626	11,559
Other assets, net	30,219	18,552
Goodwill	63,288	49,045
Total assets	$ 1,339,840	$ 1,090,241
Liabilities and unitholders equity		
Current liabilities:		
Accounts payable	$ 198,609	$ 200,428
Accrued liabilities	63,816	43,928
Fair value of derivative liabilities	89,176	130,956
Due to General Partner and affiliate	15,340	36,795
Current portion of long-term debt	397,214	169,483
Current portion of capital leases	1,313	702
Total current liabilities	765,468	582,292
Commitments and contingencies (Note 19)		
Long-term debt	418,356	401,348
Long-term capital leases	5,424	4,852
Other liabilities	17,884	15,015
Due to General Partner	988	
Deferred income taxes	15,826	15,441
Total liabilities	1,223,946	1,018,948

Unitholders equity:		
Common unitholders public (8,777,922 and 8,506,666 units issued and outstanding as of December 31, 2014 and December 31, 2013, respectively)	171,055	127,496
Common unitholders affiliated (2,034,378 and 1,571,970 units issued and outstanding as of December 31, 2014 and December 31, 2013, respectively)	(5,566)	(6,155)
Subordinated unitholders affiliated (10,071,970 units issued and outstanding)	(39,762)	(39,438)
Accumulated other comprehensive loss, net of tax	(9,833)	(10,610)
Total unitholders equity	115,894	71,293
Total liabilities and unitholders equity	$ 1,339,840	$ 1,090,241

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

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Sprague Resources LP

Consolidated and Combined Statements of Operations

(in thousands, except unit and per unit amounts)

	Years Ended 2014	2013	2012 Predecessor
Net sales	$ 5,069,762	$ 4,683,349	$ 4,043,907
Cost of products sold (exclusive of depreciation and amortization)	4,755,031	4,554,188	3,922,352
Operating expenses	62,993	53,273	47,054
Selling, general and administrative	76,420	55,210	46,449
Write-off of deferred offering costs			8,931
Depreciation and amortization	17,625	16,515	11,665
Total operating costs and expenses	4,912,069	4,679,186	4,036,451
Operating income	157,693	4,163	7,456
Gain on acquisition of business			1,512
Other (expense) income	(288)	568	(160)
Interest income	569	604	534
Interest expense	(29,651)	(30,914)	(23,960)
Income (loss) before income taxes and equity in net loss of foreign affiliate	128,323	(25,579)	(14,618)
Income tax (provision) benefit	(5,509)	(4,259)	2,796
Income (loss) before equity in loss of foreign affiliate	122,814	(29,838)	(11,822)
Equity in net loss of foreign affiliate			(1,009)
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)
Less: Predecessor (income) through October 29, 2013		(2,734)	
Less: (Income) loss attributable to Kildair from October 29, 2013 through December 8th, 2014 (Note 1)	(4,080)	2,338	
Limited partners interest in net income (loss)	$ 118,734	$ (30,234)	
Net income (loss) per limited partner unit:			
Common basic	$ 5.88	$ (1.50)	
Common diluted	$ 5.84	$ (1.50)	
Subordinated basic and diluted	$ 5.88	$ (1.50)	
Units used to compute net income (loss) per limited partner unit:			

Common basic	10,131,928	10,071,970
Common diluted	10,195,566	10,071,970
Subordinated basic and diluted	10,071,970	10,071,970
Distribution declared per common and subordinated units	$ 1.7400	$ 0.2825

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

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Sprague Resources LP

Consolidated and Combined Statements of Comprehensive Income (Loss)

(in thousands)

	Years Ended December 31,		
	2014	**2013**	**2012 Predecessor**
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)
Other comprehensive income (loss), net of tax:			
Unrealized gain on interest rate swaps. (Note 18)			
Net loss arising in the period	(531)	(376)	(1,815)
Reclassification adjustment related for losses realized in income	2,501	5,121	4,144
Net change in unrealized loss on interest rate swaps	1,970	4,745	2,329
Tax effect	(50)	(1,585)	(936)
	1,920	3,160	1,393
Foreign currency translation adjustment	(1,143)	(3,476)	928
Unrealized loss on inter-entity long-term foreign currency transactions		(3,500)	(1,936)
Other comprehensive income (loss)	777	(3,816)	385
Comprehensive income (loss)	$ 123,591	$ (33,654)	$ (12,446)

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

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Sprague Resources LP

Consolidated and Combined Statements of Member s/Unitholders Equity

(in thousands)

	Predecessor Member s Equity	Common-Public	Partnership Common-Sprague Holdings	Partnership Subordinated-Sprague Holdings	Partnership Accumulated Other Comprehensive Loss	Total
Balance at December 31, 2011	$ 184,359	$	$	$	$ (5,958)	$ 178,401
Net income	(12,831)					(12,831)
Other comprehensive income					385	385
Dividend	(26,900)					(26,900)
Capital contribution	2,151					2,151
Balance at December 31, 2012	146,779				(5,573)	141,206
Net income	2,734					2,734
Other comprehensive loss					(3,630)	(3,630)
Dividend	(40,000)					(40,000)
Capital contribution	18,835					18,835
Balance at October 29, 2013	128,348				(9,203)	119,145
Net assets not assumed by the Partnership	(154,130)				(1,221)	(155,351)
Allocation of net Parent investment to unitholders	25,782		(3,481)	(22,301)		
Proceeds from initial public offerings, net		140,251				140,251
Partnership net loss		(12,758)	(2,674)	(17,140)		(32,572)
Unit-based compensation		3		3		6
Other comprehensive loss					(186)	(186)
Balance at December 31, 2013		127,496	(6,155)	(39,438)	(10,610)	71,293
Net income		50,141	9,953	62,720		122,814
Other comprehensive income.					777	777

Unit-based compensation		1,528	286	1,803		3,617
Distribution to unitholders		(13,370)	(2,460)	(15,764)		(31,594)
Distribution to sponsor for Kildair acquisition			(17,652)	(49,015)		(66,667)
Common units issued for Kildair acquisition			10,002			10,002
Common units issued for Castle acquisition		5,318				5,318
Other contributions from Parent			470			470
Repurchased units withheld for employee tax obligation		(58)	(10)	(68)		(136)
Balance at December 31, 2014	$	$ 171,055	$ (5,566)	$ (39,762)	$ (9,833)	$ 115,894

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

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Sprague Resources LP

Consolidated and Combined Statements of Cash Flows

(in thousands)

	Years Ended December 31, 2014	2013	2012 Predecessor
Cash flows from operating activities			
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization (includes amortization of deferred debt issue costs)	22,441	20,432	14,814
Write-off of deferred offering costs			8,931
Gain on acquisition of business			(1,512)
Gain on sale of assets and insurance recoveries	(87)	(779)	(487)
Impairments on terminal asset	288		529
Provision for doubtful accounts	2,350	887	591
Undistributed loss on investment of foreign affiliate			1,009
Non-cash unit-based compensation	8,182	6	
Deferred income taxes	2,467	(9,014)	(5,389)
Changes in assets and liabilities, net of effects of contribution agreement:			
Accounts receivable	(19,135)	(158,191)	24,160
Inventories	84,456	30,635	54,373
Prepaid expenses and other assets	15,254	480	19,216
Fair value of commodity derivative instruments	(242,596)	51,487	27,208
Due to/from General Partner and affiliates	11,964	5,052	
Accounts payable, accrued liabilities and other	7,166	8,180	32,517
Net cash provided by (used in) operating activities	15,564	(80,663)	163,129
Cash flows from investing activities			
Purchases of property, plant and equipment	(18,580)	(28,090)	(7,293)
Proceeds from property insurance settlements and sale of assets	1,603	2,039	636
Acquisitions, net of cash acquired	(115,515)	(20,700)	(73,036)
Net cash used in investing activities	(132,492)	(46,751)	(79,693)
Cash flows from financing activities			
Net borrowings (payments) under credit agreements	244,739	28,387	(107,822)
Borrowings of unsecured debt			25,000

Payments on capital lease liabilities and term debt		(848)		(2,342)		(1,346)
Payments on long-term terminal obligations		(602)		(459)		(668)
Debt issue costs		(4,432)		(16,699)		(422)
Dividend paid to Parent				(40,000)		(26,900)
Distributions to unitholders		(31,594)				
Capital contribution from Parent				10,000		
Proceeds from initial public offering				140,251		
Foreign exchange on capital lease obligations		(184)				
Repurchased units withheld for employee tax obligation.		(136)				
Cash distribution to Parent in connection with initial public offering				(10,038)		
Net (payments) borrowings to Parent and affiliate		(32,035)		17,500		
Distribution to Parent for contribution of Kildair		(56,665)				
Net increase (decrease) in payable to Parent		147		(641)		598
Net cash provided by (used in) financing activities		118,390		125,959		(111,560)
Effect of exchange rate changes on cash balances held in foreign currencies		572		(190)		(14)
Net change in cash and cash equivalents		2,034		(1,645)		(28,138)
Cash and cash equivalents, beginning of period		2,046		3,691		31,829
Cash and cash equivalents, end of period	$	4,080	$	2,046	$	3,691
Supplemental disclosure of cash flow information						
Cash paid for interest	$	25,036	$	26,309	$	20,977
Cash paid for taxes	$	1,827	$	3,392	$	2,831
Fair value of common units issued in connection with acquisitions	$	15,320	$		$	

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

Sprague Resources LP

Notes to Consolidated and Combined Financial Statements

(in thousands unless otherwise stated)

1. Description of Business and Summary of Significant Accounting Policies

Company Businesses

Sprague Resources LP (the Partnership) is a Delaware limited partnership formed on June 23, 2011 to engage in activities for which limited partnerships may be organized under the Delaware Revised Limited Partnership Act including, but not limited to, actions to form a limited liability company and/or acquire assets owned by Sprague Operating Resources LLC, a Delaware limited liability company and the Partnership s operating company (the Predecessor and OLLC), an entity engaged in the sale of energy products, as well as materials handling operations.

Unless the context otherwise requires, references to Sprague Resources, and the Partnership, when used in a historical context prior to October 30, 2013, refer to Sprague Operating Resources LLC, the Predecessor for accounting purposes and the successor to Sprague Energy Corp., also referenced as the Predecessor and when used in the present tense or prospectively, refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to Axel Johnson or the Parent refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its general partner. References to Sprague Holdings refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of the General Partner. References to the general partner refer to Sprague Resources GP LLC.

The Partnership is one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. The Partnership owns, operates and/or controls a network of 19 refined products and materials handling terminals located in the Northeast United States and in Quebec, Canada. The Partnership also utilizes third-party terminals in the Northeast United States through which it sells or distributes refined products pursuant to rack, exchange and throughput agreements. The Partnership has four business segments: refined products, natural gas, materials handling and other operations. The refined products segment purchases a variety of refined products, such as heating oil, diesel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (primarily from refining companies, trading organizations and producers), and sells them to wholesale and commercial customers. The natural gas segment purchases, sells and distributes natural gas to commercial and industrial customers in the Northeast and Mid-Atlantic United States. The Partnership purchases the natural gas it sells from natural gas producers and trading companies. The materials handling segment offloads, stores and prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, crude oil, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. The Partnership s other operations include the purchase and distribution of coal and certain commercial trucking activities. As of December 31, 2014 our general partner employs over 580 full-time employees who support the Partnership s operations, of which approximately 8% are covered by collective bargaining agreements and Kildair has approximately 100 employees, of which approximately 36% are covered by collective bargaining agreements.

Since 2007 and through September 30, 2012, the Predecessor, through its wholly-owned foreign subsidiary, Sprague Energy Canada Ltd., owned a 50% equity investment in 9047-1137 Quebec Inc. (Kildair). Kildair owns a terminal in Sorel-Tracy, Quebec, on the St. Lawrence River where it maintains 3.3 million barrels of residual fuel, asphalt, and crude oil storage. Kildair s primary businesses include marketing of residual fuel oil both locally and for export, marketing of asphalt including polymer modified grades, and crude-by-rail handling services. Kildair s terminal has blending infrastructure allowing the ability to process a wide range of varying quality blend components. The facility also includes an asphalt and residual fuel oil testing laboratory, 25 truck and railcar loading and offloading racks, 120 railcars of offloading capacity, including 60 in the new crude oil rail offloading section, and a dock with the capability to receive ships with up to 450,000 barrels of capacity. On October 1, 2012, the Predecessor acquired the remaining 50% equity interest in Kildair (see Note 3). Kildair s results of operations are not included in the results of the Partnership s operations prior to October 1, 2012, as it was accounted for as an equity method investment.

In connection with the completion on October 30, 2013 of the initial public offering (the IPO) of limited partner interests of the Partnership, Axel Johnson Inc. (the Parent or Axel Johnson) contributed to Sprague Holdings all of the ownership interests in the Predecessor. The Predecessor distributed to a wholly owned subsidiary of Sprague Holdings certain assets and liabilities, its ownership of Kildair and accounts receivable and cash in an aggregate amount equal to the net proceeds of the IPO. Sprague Holdings then contributed all of the ownership interests in the Predecessor to the Partnership. All of the assets and liabilities of the Predecessor contributed to the Partnership by Sprague Holdings were recorded at the Parent s historical cost, as the foregoing transactions are among entities under common control.

On December 9, 2014, the Partnership acquired all of the equity interest in Kildair through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties, LLC, from a wholly owned subsidiary of Sprague Holdings. As this transaction represents a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast to include the historical results of Kildair for all periods presented where Kildair was controlled by Axel Johnson, which commenced on October 1, 2012. Limited partners interest in net income (loss) as well as the related per unit amounts have not been recast.

Basis of Presentation

The Consolidated and Combined Financial Statements include the accounts of the Partnership commencing October 30, 2013, and the Predecessor and its wholly-owned subsidiaries through October 30, 2013. Intercompany transactions between the Partnership, Predecessor and its subsidiaries have been eliminated. Investments in affiliated companies, greater than 20% voting interest or where the Partnership or Predecessor exerts significant influence over an investee but lacks control over the investee are accounted for using the equity method. For the year ended December 31, 2013, the financial statements for the Partnership and the Predecessor are presented on a combined basis as the entities were under common control.

Use of Estimates

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

Revenue Recognition and Cost of Products Sold

The Partnership recognizes revenue on refined products, natural gas and materials handling revenue-producing activities, net of applicable provisions for discounts and allowances. Allowances for cash discounts are recorded as a reduction of revenue at the time of sale. Cash discounts were $8.9 million, $7.8 million and $7.5 million for the years ended December 31, 2014, 2013 and 2012, respectively. At the time of sale for all revenue producing activities, persuasive evidence of an arrangement exists, delivery or service has occurred, the price is fixed or determinable, and collectability is reasonably assured.

Refined products revenue-producing activities are direct sales to customers including throughput and exchange locations. 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. Natural gas revenue-producing activities are sales to customers at various points on natural gas pipelines or at local distribution companies (*i.e.*, utilities). Revenue is recognized when the product is delivered. Materials handling service revenue is recognized monthly over the contractual service period or when the service is rendered. Revenue from other activities, primarily coal distribution and transportation services, is recognized when the product is delivered or the services are rendered.

The allowance for doubtful accounts is recorded to reflect an estimate of the ultimate realization of the Partnership accounts receivable and includes an assessment of customers creditworthiness and the probability of collection. The allowance reflects an estimate of specifically identified accounts at risk. The provision for the allowance for doubtful accounts is included in cost of products sold.

Shipping costs that occur at the time of sale are included in cost of products sold. Various excise taxes collected at the time of sale and remitted to authorities are recorded on a net basis.

Commodity Derivatives

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. On a limited basis and within the Partnership s risk management guidelines, the Partnership utilizes derivatives to generate profits 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 the Consolidated Balance Sheets. 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 in the Consolidated Balance Sheets. Substantially all of the Partnership s commodity derivative contracts outstanding as of December 31, 2014 will settle prior to June 30, 2016.

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 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 December 31, 2014 or 2013.

Interest Rate Derivatives

The Partnership manages its exposure to variable LIBOR borrowings by using interest rate swaps to convert a portion of its variable rate debt to fixed rates. These interest rate swaps are designated as cash flow hedges and the effective portion of changes in fair value of the swaps are included as a component of comprehensive income (loss) and accumulated other comprehensive income (loss), net of tax, in the Consolidated and Combined Statements of Comprehensive Income (Loss) and in the Consolidated Balance Sheets, respectively. The ineffective portion of the changes in fair value of the swaps, which was not material, is recorded in interest expense.

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To designate a derivative as a cash flow hedge, the Partnership documents at inception the assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. The assessment, updated at least quarterly, is based on the most recent relevant historical correlation between the derivative and the item hedged. If during the term of the derivative, the hedge is found to be less than highly effective, hedge accounting is prospectively discontinued and the remaining gains and losses are reclassified to income in the current period.

Market and Credit Risk

The Partnership manages the risk fluctuations in the price and transportation costs of its commodities through the use of derivative instruments. The volatility of prices for energy commodities can be significantly influenced by market supply and demand, changes in seasonal demand, weather conditions, transportation availability, and federal and state regulations. The Partnership monitors and manages its exposure to market risk on a daily basis in accordance with approved policies.

The Partnership has a number of financial instruments that are potentially at risk including cash and cash equivalents, receivables and derivative contracts. The Partnership s primary exposure is credit risk related to its receivables and counterparty performance risk related to its derivative assets, which is the loss that may result from a customer s or counterparty s non-performance. The Partnership uses 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, and accepting personal guarantees and various forms of collateral.

The Partnership believes that the counterparties to its derivative contracts will be able to satisfy their contractual obligations. Credit risk is limited by the large number of customers and counterparties comprising the Partnership s business and their dispersion across different industries.

The Partnership s cash is 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. The Partnership has not experienced any losses on such accounts.

Fair Value Measurements

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 in accordance with Accounting Standards Codification (ASC) 820, *Fair Value Measurement* which established a hierarchy for the inputs used to measure the fair value of financial assets and liabilities based on the source of the input, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using significant unobservable inputs (Level 3). Multiple inputs may be used to measure fair value; however, the level of fair value is based on the lowest significant input level within this fair value hierarchy.

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

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

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter 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.

Earnings (Loss) Per Unit

The Partnership computes income per unit using the two-class method. Net income (loss) attributable to common unitholders and subordinated unitholders for purposes of the basic income (loss) per unit computation is allocated between the common unitholders and subordinated unitholders by applying the provisions of the partnership agreement. Under the two-class method, any excess of distributions declared over net income (loss) is allocated to the partners based on their respective sharing of income specified in the partnership agreement. Net income (loss) per unit is determined by dividing the net income (loss) allocated to the common unitholders and the subordinated unitholders under the two-class method by the number of common units and subordinated units outstanding at December 31, 2014 and 2013.

Sprague Holdings owns all of the outstanding subordinated units and the incentive distribution rights (IDR) as of December 31, 2014. Pursuant to the partnership agreement, to the extent that the quarterly distributions exceed certain targets, Sprague Holdings is entitled to receive certain incentive distributions that will result in more net income (loss) proportionately being allocated to Sprague Holdings than to the other holders of common units.

Financial Accounting Standards Board (FASB) Accounting Standards Codification 260 (ASC 260) *Earnings per Share* addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity. The application of ASC 260 may have an impact on earnings per limited partner common and subordinated units in future periods if there are material differences between net income (loss) and actual cash distributions or if other participating units are issued.

Cash and Cash Equivalents

Cash and cash equivalents include cash and highly liquid investments which are readily convertible into cash and have maturities of three months or less when purchased.

Inventories

The Partnership s inventories are valued at the lower of cost or market. Cost is primarily determined using the first-in, first-out method, except for Kildair, which used the weighted average method. Inventory consists of petroleum products, natural gas, asphalt and coal. The Partnership uses derivative instruments, primarily futures, forwards and swaps, to economically hedge substantially all of its inventory.

Property, Plant and Equipment, Net

Property, plant and equipment, net are recorded at historical cost. Depreciation is computed on a straight-line basis over the following estimated useful lives:

Furniture and fixtures	5 to 10 years
Plant, machinery and equipment	5 to 30 years
Building and leasehold improvements	10 to 25 years

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Leasehold improvements are amortized over the term of the lease or the estimated useful life of the improvement, whichever is shorter. Maintenance and repairs are charged to expense as incurred. Costs and related accumulated depreciation of properties sold or otherwise disposed of are removed from the respective accounts, and any resulting gains or losses are recorded at that time.

Long-lived Asset Impairment

The Partnership evaluates the carrying value of its property, plant and equipment and finite lived intangible assets for impairment when events or changes in circumstances indicate the carrying amount may not be recoverable based on estimated future undiscounted cash flows. Future cash flow projections include assumptions of future sales levels, the impact of cost reduction programs, and the level of working capital needed to support each business. To the extent the carrying amount of the asset group is not recoverable based on undiscounted cash flows, the amount of impairment is measured by the difference between the carrying value and the fair value of the individual assets.

Purchase Price Allocation

The Partnership and the Predecessor allocate the cost of an acquired entity to the assets acquired and liabilities assumed based on their respective fair values at the date of acquisition. Property, plant and equipment and goodwill generally represent large components of these acquisitions. In addition to goodwill, intangible assets acquired typically includes customer relationships and non-compete agreements. Goodwill is calculated as the excess of the cost of the acquired entity over the net of the fair value of the assets acquired and the liabilities assumed. Customer relationships and non-compete agreements are valued based on an excess earnings or income approach based on projected cash flows.

Other assets acquired and liabilities assumed typically include, but are not limited to, inventory, accounts receivable, accounts payable and other working capital items. Because of their short-term nature, the fair values of these other assets and liabilities generally approximate the book values on the acquired entity s balance sheet.

Goodwill

Goodwill is not amortized but tested for impairment at the reporting unit level, at least annually (as of October 31 each year), by determining the fair value of the reporting unit and comparing it to its carrying value, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, the Partnership will determine if there is a potential impairment by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than the carrying amount, an impairment loss would be reported. The Partnership assesses the fair value of its reporting units based on a discounted cash flow valuation model (Level 3 measurement). The key assumptions used are discount rates and growth rates, applied to cash flow projections. These assumptions contemplate business, market and overall economic conditions.

After applying the discounted cash flow methods to measure the fair value of its reporting units, including the consideration of reasonably likely adverse changes in the rates and assumptions described above, the Partnership determined that there have been no goodwill impairments to date. In performing the discounted cash flow analysis, the Partnership used a range of discount rate assumptions to evaluate the sensitivity on the fair values resulting from the discounted cash flow valuation.

Intangibles, Net

Intangibles, net consist of intangible assets with finite lives, including customer relationships and covenants not to compete. Intangibles and other assets are amortized over their respective estimated useful lives. The Partnership evaluates its intangible and other assets for impairment when indicators are present.

Income Taxes

The Partnership is organized as a pass-through entity for U.S. federal income tax purposes. As a result, the partners are responsible for U.S. federal income taxes based on their respective share of taxable income. Net income (loss) for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. The Partnership, however, is subject to a statutory requirement that non-qualifying income cannot exceed 10% of total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of non-qualifying income exceeds this statutory limit, the Partnership would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through a taxable corporate subsidiary, Sprague Energy Solutions, Inc. Sprague Energy Solutions, Inc. is subject to U.S. federal, state income tax and pays any income taxes related to the results of its operations. For the year ended December 31, 2014, the Partnership s non-qualifying income did not exceed the statutory limit. The Partnership is subject to income tax and franchise tax in certain domestic state and local as well as foreign jurisdictions.

Prior to the IPO, the Predecessor was not a separate taxable entity for U.S. federal and certain state income tax purposes and its results were included in the consolidated U.S. federal and certain state income tax returns of Lexa International Corporation, which is the sole shareholder of the Predecessor s Parent. Income tax provisions and benefits, related tax payments, and current and deferred tax balances were prepared as if the Predecessor operated as a stand-alone taxpayer for all periods presented in accordance with the tax sharing agreement between the Predecessor and the Parent. Under the tax sharing agreement, the Predecessor is obligated to pay U.S. federal and certain state taxes to the Parent. In the event that the Parent does not have a consolidated liability for U.S. federal or certain state taxes, the Predecessor is not obligated to pay the Parent for such taxes and all such amounts are reflected as capital contributions.

Income taxes are provided using the asset and liability method prescribed by ASC 740, *Income Taxes*. Under this method, income taxes (*e.g*., deferred tax assets, deferred tax liabilities, taxes currently payable and tax expense) are recorded based on amounts refundable or payable in the current year and include the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Deferred taxes are measured by applying currently enacted tax rates. The Partnership establishes a valuation allowance for deferred tax assets when it is more likely than not that these assets will not be realized.

All of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes and are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from our Canadian entities to other Sprague entities are subject to Canadian withholding tax that is treated as income tax expense.

The Partnership recognizes the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. The Partnership classifies interest and penalties associated with uncertain tax positions as income tax expense.

Foreign Currency

Prior to December 31, 2013, the functional currency of Kildair was the Canadian dollar. All balance sheet asset and liability accounts were translated to U.S. dollars using rates of exchange in effect at the balance sheet dates, and its results of operations were translated using average exchange rates for the relevant period. Resulting translation adjustments were recorded as a component of member s/unitholders equity in accumulated other comprehensive loss.

On January 1, 2014, the Partnership changed the functional currency of Kildair from the Canadian Dollar to the U.S. Dollar as a result of performing a review of the appropriateness of the status of the functional currency for this subsidiary. The functional currency of the Partnership s other Canadian subsidiaries (Wintergreen and Transit) remains the Canadian Dollar. The Partnership s reporting currency is the U.S. dollar. In accordance with ASC-830 Foreign Currency Matters , the change took place prospectively on the first day of the fiscal year, there was no income statement or cash flow translation required and translation adjustments for prior periods were not removed from equity.

Kildair converts receivables and payables denominated in other than their functional currency at the exchange rate as of the balance sheet date. Kildair utilizes forward currency contracts to manage its exposure to currency fluctuations of certain of its transactions that are denominated in Canadian dollars. These forward currency exchange contracts are recorded at fair value at the balance sheet date and changes in fair value are recognized in net income (loss) as these forward currency contracts have not been designated as hedges. For the years ended December 31, 2014, 2013 and 2012, transaction exchange gains or losses, except for certain transaction gains or losses related to intercompany receivable and payables, amounted to a gain of $0.5 million and losses of $7.9 million and $1.4 million, respectively, which is recorded in cost of products sold in the Consolidated and Combined Statements of Operations.

Transaction gains and losses related to intercompany receivables and payables not anticipated to be settled in the foreseeable future are excluded from the determination of net income (loss) and are recorded as a translation adjustment to accumulated other comprehensive loss as a component of member s/unitholders equity.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standard Update 2014-09, *Revenue from Contracts with Customers*, 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 Partnership continues to evaluate both the impact of this new standard on the consolidated financial statements and the transition method it will utilize for adoption. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted.

In April 2014, the Financial Accounting Standards Board issued Accounting Standard Update 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. This ASU revises the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. The Partnership has early adopted this guidance on a prospective basis. The adoption did not have an impact on the Partnership s consolidated financial statements.

2. Initial Public Offering

On October 30, 2013, in connection with the closing of the IPO, 8,500,000 of the Partnership s common units, representing a 42.2% limited partner interest in the Partnership, were sold to the public at an initial public offering price of $18.00 per unit. Net proceeds of the sale of the common units were $140.3 million after deducting underwriting discounts and commissions, the structuring fee and offering expenses. Immediately after the IPO, Sprague Holdings owned 1,571,970 common units and 10,071,970 subordinated units, which represented an aggregate 57.8% limited partner interest in the Partnership.

The following table is a reconciliation of cash proceeds from the IPO (in millions):

Gross proceeds	$ 153.0
Less: Underwriting and structuring fees and other offering expenses	(12.7)
Net proceeds from the IPO used for reduction of working capital facility	$ 140.3

Sprague Holdings owns, 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 have the right to receive distributions of cash from distributable cash flow each quarter in an amount equal to $0.4125 per common unit, which is the amount defined in the partnership agreement as the minimum quarterly distribution, 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. Furthermore, no arrearages will accrue or be paid on the subordinated units. Upon expiration of the subordination period, any outstanding arrearages in payment of the minimum quarterly distribution on the common units will be extinguished (not paid), each outstanding subordinated unit will immediately convert into one common unit and will thereafter participate pro rata with the other common units in distributions.

Sprague Holdings currently holds incentive distribution rights 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 50.0% does not include any distributions that Sprague Holdings may receive on any limited partner units that it owns.

The partnership agreement contains provisions for the allocation of net income (loss) to the unitholders. For purposes of maintaining partner capital accounts, the partnership agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interest. Normal allocations according to percentage interests are made after giving effect, if any, to priority income allocations in an amount equal to incentive cash distributions allocated 100% to Sprague Holdings.

Contribution, Conveyance and Assumption Agreement

On October 30, 2013, in connection with the closing of the IPO, the Parent, Sprague Holdings, the Partnership, Sprague Resources GP LLC, a Delaware limited liability company and the general partner of the Partnership (the General Partner), Sprague Massachusetts Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague Holdings (Sprague Massachusetts), Sprague International Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague Holdings (Sprague International), Sprague Canadian Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague International (Sprague Canadian) and the OLLC entered into a contribution, conveyance and assumption agreement (the Contribution Agreement). Pursuant to the Contribution Agreement, among other things, Sprague Holdings conveyed all of the ownership interests in the Predecessor to the Partnership (through the OLLC), in exchange for (a) 1,571,970 common units, representing a 7.8% limited partner interest in the Partnership, (b) 10,071,970 subordinated units, representing a 50% limited partner interest in the Partnership, (c) all of the equity interests in the Partnership classified as incentive distribution rights under the amended and restated agreement of limited partnership of the Partnership and (d) the right to receive the deferred issuance and distribution (as defined in the Contribution Agreement).

Omnibus Agreement

On October 30, 2013, in connection with the closing of the IPO, the Partnership, the Parent, Sprague Holdings and the General Partner, entered into an omnibus agreement (the Omnibus Agreement). The Omnibus Agreement addresses the agreement of the Parent to offer to the Partnership, and to cause the Parent s controlled affiliates to offer to the Partnership, opportunities to acquire certain businesses and assets and the obligation of Sprague Holdings to indemnify the Partnership for certain liabilities. Pursuant to the Omnibus Agreement, the Parent agreed to continue to provide credit support to the Partnership, consistent with past practice, through December 31, 2016, if and to the extent such services are necessary and reasonable, and the Partnership agreed to use its commercially reasonable efforts to reduce, and eventually eliminate, the need for trade credit support from the Parent. The Omnibus Agreement may be terminated (other than with respect to the indemnification provisions) by any party to the Omnibus Agreement in the event that the Parent, directly or indirectly, owns less than 50% of the voting equity power of the General Partner.

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Services Agreement

On October 30, 2013, in connection with the closing of the IPO, the Partnership, the General Partner and Sprague Holdings, entered into an operational services agreement (the Services Agreement). Pursuant to the Services Agreement, the General Partner will provide certain general and administrative and operational services to the Partnership and Sprague Holdings, and the Partnership and Sprague Holdings will reimburse the General Partner for all costs and expenses incurred in connection with providing such services to the Partnership and Sprague Holdings. The Services Agreement does not limit the amount that may be reimbursed or paid by the Partnership to the General Partner. The initial term of the Services Agreement will expire on October 30, 2018.

The Services Agreement will automatically renew at the end of the initial term for successive one-year terms until terminated in accordance with the terms thereof. The Services Agreement does not limit the ability of the officers and employees of the General Partner to provide services to other affiliates of Sprague Holdings or unaffiliated third parties (see Note 13).

Long-Term Incentive Plan

The General Partner adopted the Sprague Resources LP 2013 Long-Term Incentive Plan (the LTIP) effective immediately prior to the effective date of the IPO, for the benefit of employees, consultants and directors of the General Partner and its affiliates, who provide services to the General Partner or an affiliate. The LTIP provides the Partnership with the flexibility to grant unit options, restricted units, phantom units, unit appreciation rights, cash awards, distribution equivalent rights, substitute awards and other unit-based awards or any combination of the foregoing.

The LTIP limits the number of common units that may be delivered, pursuant to vested awards, to 800,000 common units. On January 1 of each calendar year occurring after the second anniversary of the effective date and prior to the expiration of the LTIP, the total number of common units reserved and available for issuance under the LTIP will increase by 200,000 common units.

The LTIP will expire upon the earlier of (i) its termination by the board of directors of the General Partner, (ii) the date common units are no longer available under the LTIP for grants or (iii) the tenth anniversary of the date the LTIP was approved by the General Partner.

3. Business Combinations
Kildair

Prior to October 1, 2012

In October 2007, the Predecessor purchased a 50% equity interest in Kildair for $38.7 million. The share purchase agreement provided for the Predecessor to acquire the remaining 50% of Kildair in 2012, subject to terms and conditions within the discretion of the Predecessor, for an additional $27.5 million Canadian, plus a potential earn-out payment if EBITDA over the five year period exceeded $55.0 million Canadian. The difference between the acquisition cost and the fair value of net assets acquired in October 2007 of $13.2 million was allocated to various assets and liabilities based on their respective fair values with amortization recorded over the useful lives of the assets or liabilities that gave rise to the difference. Through September 30, 2012, the investment in Kildair was accounted for using the equity method of accounting and the Predecessor s share of its results were recorded as equity in net loss of foreign affiliate in the Consolidated and Combined Statements of Operations.

The Predecessor s equity share of earnings from its investment in Kildair, which includes amortization of the excess of the fair value over the cost of the assets acquired, was a loss of $1.0 million, net of tax, for the period from January 1, 2012 to September 30, 2012.

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From October 1, 2012 through October 30, 2013

On October 1, 2012, the Predecessor acquired control of Kildair by purchasing the remaining 50% equity interest. Since the acquisition date, the assets, liabilities and results of operations of Kildair have been consolidated into the Predecessor s consolidated financial statements.

The acquisition-date fair value of the consideration paid to the previous 50% owner of Kildair consisted of cash of $73.0 million (including an $8.7 million redemption of preferred shares) and the fair value of the Predecessor s previous 50% equity interest. The Predecessor recognized a gain of $1.5 million as a result of re-measuring to fair value its prior equity interest held before the business combination. The fair value was determined using valuation techniques including the discounted cash flow approach and the market multiple approach (enterprise value of earnings before interest, taxes, depreciation and amortization). The discounted cash flow approach incorporates assumptions including estimated future cash flows and a discount rate that reflects consideration of risk free rates as well as market risk. The market multiple approach incorporates market information from comparable companies. The gain, which resulted in no income tax expense, was recorded in 2012 as gain on acquisition of a business in the Consolidated and Combined Statements of Operations.

The Predecessor determined the fair value of property, plant and equipment using the replacement cost approach and determined the fair value of intangible assets using income approaches that incorporated projected cash flows and relief from royalty methodologies. The Predecessor s analysis of fair value factors indicated that for substantially all other assets and liabilities that book value approximated fair value.

The goodwill recognized is primarily attributable to Kildair s assembled workforce, its reputation in Eastern Canada and the Northeast United States and the residual cash flow the Predecessor believes that it will be able to generate. None of the goodwill is deductible for income tax purposes.

Acquisition by the Partnership on December 9, 2014

On December 9, 2014, the Partnership acquired all of the equity interests in Kildair through the acquisition of its ownership in Kildair s parent, Sprague Canadian Properties LLC, for total consideration of $175.0 million (a portion of which was used to retire Kildair debt), which included $10.0 million in unregistered common units of Sprague Resources LP. As the acquisition of Kildair by the Partnership represents a transfer of entities under common control, the Consolidated and Combined Financial Statements and related information presented herein have been recast by including the historical financial results of Kildair for all periods that were controlled by Axel Johnson. As such, summarized financial information has not been presented.

The Partnership recognized $1.7 million of acquisition related costs that were expensed in 2014 and are included in selling, general and administrative expense in the accompanying Consolidated and Combined Statements of Operations.

Acquisition of Castle Oil

On December 8, 2014, the Partnership acquired substantially all of the assets of Castle Oil (Castle) and certain of its affiliates by purchasing Castle s Bronx, New York terminal and its associated wholesale, commercial, and retail fuel distribution business. The acquisition-date fair value of the consideration consisted of cash of $45.3 million, an obligation to pay $5.0 million over a three year period (net present value of $4.6 million) and approximately $5.3 million in unregistered common units, plus payments for Castle s inventory and other current assets of approximately $37.0 million. Castle s Bronx terminal is a large deep water petroleum products terminal located in New York City and has 0.9 million barrels of storage capacity, The purchase of this facility augments the Partnership s supply, storage and marketing opportunities and provides new opportunities in refined fuels, and expanded materials handling capabilities. The acquisition was accounted for as a business combination and was financed with borrowings under the Partnership s credit facility.

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The following table summarizes the preliminary fair values of the assets acquired:

Inventories	$ 36,512
Derivative assets	4,837
Other current assets and prepaids	533
Property plant and equipment	48,316
Intangibles and other assets	6,631
Total identifiable assets acquired	96,829
Accrued liabilities	2,018
Derivative liabilities	390
Long term capital leases	1,503
Other liabilities	761
Total liabilities assumed	4,672
Net assets acquired	$ 92,157

A preliminary allocation of the purchase price to the assets acquired and liabilities assumed was made based on available information and incorporating management s best estimates. The Partnership is currently in the process of finalizing the valuation of the assets acquired and liabilities assumed. The actual allocation of the final purchase price and resulting effect on income from operations may differ from the amount included above. The Partnership expects to finalize the purchase allocation during 2015.

The following represent the unaudited pro forma consolidated net sales and net income (loss) as if Castle had been included in the consolidated results of the Partnership for the twelve months ended December 31, 2014 and 2013:

	For the Years Ended December 31,	
	2014	**2013**
Net sales	$ 5,796,440	$ 5,522,226
Net income (loss)	$ 124,101	$ (15,021)
Limited partners interest in net income (loss)	$ 120,021	$ (15,417)
Net income (loss) per limited partner common unit basic	$ 5.87	$ (0.76)
Net income (loss) per limited partner common unit diluted	$ 5.86	$ (0.76)

These amounts have been calculated after applying the Partnership s accounting policies and adjusting the results of Castle to reflect the depreciation and amortization that would have been charged assuming the fair value adjustments to property, plant and equipment; and intangible assets had been applied on January 1, 2013, together with an adjustment to reflect taxes as a pass-through entity for U.S. federal income tax purposes. Castle s net sales and net income included in the Partnership s consolidated operating results from December 8, 2014, the acquisition date, through the year ended December 31, 2014 were $43.0 million and $1.2 million, respectively.

The Partnership recognized $1.1 million of acquisition related costs that were expensed in 2014 and are included in selling, general and administrative expense in the accompanying Consolidated and Combined Statements of Operations.

Acquisition of Metromedia Gas & Power, Inc.

On October 1, 2014, the Partnership completed its purchase of Metromedia Gas & Power Inc. (Metromedia Energy) for $22.0 million, not including the purchase of natural gas inventory, utility security deposits, and other adjustments. Total consideration at closing was $32.8 million. Metromedia Energy markets natural gas and brokers electricity to commercial, industrial and municipal consumers primarily in the Northeast and Mid-Atlantic United States. The acquisition was accounted for as a business combination and was financed with borrowings under the Partnership s credit facility.

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

Inventories	$ 1,365
Derivative assets	24,971
Other current assets	543
Intangible assets	13,900
Natural gas transportation assets	39,427
Other long term assets	6,683
Property, plant, and equipment	556
Total identifiable assets acquired	87,445
Derivative liabilities	67,413
Other current liabilities	52
Natural gas transportation liabilities	1,458
Total liabilities assumed	68,923
Net identifiable assets acquired	18,522
Goodwill	14,243
Net assets acquired	$ 32,765

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

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

The Partnership recognized $0.1 million of acquisition related costs that were expensed in 2014 and are included in selling, general and administrative expense in the accompanying Consolidated and Combined Statements of Operations.

Bridgeport Terminal

On July 31, 2013, the Predecessor purchased an oil terminal in Bridgeport, Connecticut for $20.7 million. This deep water facility includes 13 storage tanks with 1.3 million barrels of storage capacity for gasoline and distillate products with 11 storage tanks and 1.1 million barrels currently in service. The terminal will provide throughput services to third-parties for branded gasoline sales, and is expected to increase the Predecessor s marketing of refined products, both gasoline and distillate, in the Connecticut market.

The acquisition was accounted for as a business combination and was financed with a capital contribution of $10.0 million from the Parent (see Note 13) and $10.7 million of borrowings under the acquisition line of the Predecessor s credit facility.

The following table summarizes the fair values of the assets acquired:

Property, plant and equipment	$ 20,190
Intangible assets customer relationships	510
Net assets acquired	$ 20,700

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The Predecessor incurred $0.2 million of acquisition related costs that were recorded as selling, general and administrative expense at the acquisition date.

4. Accumulated Other Comprehensive Loss, Net of Tax

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

	As of December 31, 2014	As of December 31, 2013
Fair value of interest rate swaps, net of tax	$ (406)	$ (2,326)
Cumulative foreign currency translation adjustment	(9,427)	(8,284)
Accumulated other comprehensive loss, net of tax	$ (9,833)	$ (10,610)

The cumulative foreign currency translation loss adjustment as of December 31, 2013 includes a cumulative loss of $0.5 million, respectively related to the conversion of affiliate advances not anticipated to be settled in the foreseeable future.

A summary of the changes in accumulated other comprehensive income (loss) related to foreign currency translation is as follows:

	Years Ended December 31, 2014	2013	2012
Balance-beginning of period	$ (8,284)	$ (1,308)	$ (300)
Foreign currency translation adjustment	(1,143)	(3,476)	928
Unrealized loss on inter-entity long-term foreign currency translation		(3,500)	(1,936)
Balance-end of period	$ (9,427)	$ (8,284)	$ (1,308)

5. Accounts Receivable, Net

	As of December 31, 2014	As of December 31, 2013
Accounts receivable, trade	$ 280,657	$ 265,842
Less allowance for doubtful accounts	(3,976)	(1,607)
Net accounts receivable, trade	276,681	264,235
Accounts receivable, other	12,743	10,452
Accounts receivable, net	$ 289,424	$ 274,687

Unbilled accounts receivable, included in accounts receivable, trade, at December 31, 2014 and 2013 were $64.1 million and $71.0 million, respectively. Unbilled receivables relate primarily to the delivery and sale of natural gas to customers in the current month for which the right to bill exists. Such amounts generally are invoiced to the customer the following month when actual usage data becomes available.

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A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	Balance at Beginning of Period	Charged to Expense	Charged (to) from Another Account	Deductions	Balance at End of Period
Balance, December 31, 2014:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1,607	$ 2,350	$ 84	$ 65	$ 3,976
Allowance for notes receivable	3,515		(84)	1,064	2,367
Total	$ 5,122	$ 2,350	$	$ 1,129	$ 6,343
Balance, December 31, 2013:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 2,556	$ 559	$ (740)	$ 768	$ 1,607
Allowance for notes receivable	2,847	328	740	400	3,515
Total	$ 5,403	$ 887	$	$ 1,168	$ 5,122
Predecessor Balance, December 31, 2012:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 3,743	$ 591	$ (844)	$ 934	$ 2,556
Allowance for notes receivable	2,269		844	266	2,847
Total	$ 6,012	$ 591	$	$ 1,200	$ 5,403

Notes receivable, net of allowance, are generally long-term arrangements and are included in other assets, net in the Partnership s Consolidated Balance Sheets.

6. Inventories

	As of December 31, 2014	2013
Petroleum and related products	$ 366,431	$ 414,290
Asphalt	18,357	19,141
Coal	2,380	1,886
Natural gas	3,387	1,818
Inventories	$ 390,555	$ 437,135

Due to changing market conditions, the Partnership recorded a provision of $50.5 million, $1.7 million and $6.3 million as of December 31, 2014, 2013 and 2012, respectively, to write-down petroleum, natural gas and asphalt inventory to its net realizable value. These charges are included in cost of products sold in the Consolidated and Combined Statements of Operations.

7. Other Current Assets

	As of December 31, 2014	As of December 31, 2013
Margin deposits with brokers	$ 22,779	$ 18,765
Natural gas transportation, current portion	11,748	
Prepaid petroleum products	8,071	5,428
Income tax receivable	436	1,640
Other	9,382	5,603
Other current assets	$ 52,416	$ 31,436

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8. Property, Plant and Equipment, Net

	As of December 31, 2014	2013
Plant, machinery, furniture and fixtures	$ 293,080	$ 243,861
Building and leasehold improvements	14,565	13,493
Land and land improvements	60,395	25,418
Construction in progress	3,238	23,212
Property, plant and equipment, gross	371,278	305,984
Less: accumulated depreciation	(121,152)	(107,508)
Property, plant and equipment, net	$ 250,126	$ 198,476

Depreciation expense for the years ended December 31, 2014, 2013 and 2012 was $14.5 million, $13.8 million and $10.7 million, respectively.

Property, plant and equipment include the following amounts for capital leases:

	As of December 31, 2014	2013
Plant, machinery, furniture and fixtures	$ 16,931	$ 15,539
Building and leasehold improvements	4,719	4,281
Land and land improvements	251	251
Property, plant and equipment, gross	21,901	20,071
Less: accumulated amortization	(8,175)	(6,895)
Property, plant and equipment, net	$ 13,726	$ 13,176

Amortization expense on capital leased assets for the years ended December 31, 2014, 2013 and 2012 was $1.3 million, $1.3 million and $0.9 million, respectively.

9. Intangibles, Net

	As of December 31, 2014			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	5-16	$ 31,961	$ 6,853	$ 25,108
Other	5-7	4,671	2,153	2,518

Intangible assets, net		$ 36,632	$ 9,006	$ 27,626

	As of December 31, 2013			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	5-14	$ 13,735	$ 4,620	$ 9,115
Other	7	3,672	1,228	2,444
Intangible assets, net		$ 17,407	$ 5,848	$ 11,559

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The Partnership recorded amortization expense related to intangible assets of $3.2 million, $2.7 million and $0.9 million during the years ended December 31, 2014, 2013 and 2012, respectively. The amortization of intangible assets is recorded in depreciation and amortization expense in the accompanying Consolidated and Combined Statements of Operations.

During the years ended December 31, 2014, the Partnership acquired intangible assets of $19.2 million (consisting of $18.2 million of customer relationships and $1.0 million of other intangibles). During the years ended December 31, 2013 and 2012, the Predecessor acquired intangible assets of $0.5 million of customer relationships and $13.9 million (consisting of $9.9 million of customer relationships and $4.0 million of other intangibles), respectively (see Note 3).

Amortization of intangible assets is calculated by the sum-of-the-years -digits method over the periods of expected benefit. The Partnership believes the sum-of-the-years -digits method of amortization properly reflects the timing of the recognition of the economic benefits realized from its intangible assets. The estimated future annual amortization expense of intangible assets for the years ending December 31, 2015, 2016, 2017, 2018 and 2019 is $4.6 million, $4.0 million, $3.4 million, $2.9 million and $2.5 million, respectively. As acquisitions and dispositions occur in the future, these amounts may vary.

10. Other Assets, Net

	As of December 31,	
	2014	**2013**
Deferred debt issuance costs	$ 15,487	$ 15,910
Deposits	6,893	1,005
Natural gas transportation, long-term portion	5,677	
Other	2,162	1,637
Other assets, net	$ 30,219	$ 18,552

Deferred Debt Issuance Costs

The Partnership recorded amortization expense related to deferred debt issuance costs of $4.8 million, $3.9 million and $3.1 million during the years ended December 31, 2014, 2013 and 2012, respectively. Deferred debt issuance costs are amortized over the life of the related debt on a straight-line basis and recorded in interest expense in the accompanying Consolidated and Combined Statements of Operations.

Natural Gas Transportation Assets

In connection with the Metromedia Energy acquisition, the Partnership recorded an asset in the amount of $39.4 million, and a liability in the amount of $1.5 million, representing the fair value of natural gas transportation contracts acquired. These assets and liabilities will be amortized into cost of products sold in our natural gas segment over the life of the underlying agreements. During the year ended December 31, 2014, the Partnership recorded a charge to cost of products sold of $21.9 million which included $13.6 million due to a decline in value as a result of decreasing natural gas spreads. The estimated future expense of the net natural gas transportation assets for the years ended December 31, 2015, 2016 and 2017 is $10.8 million, $4.6 million, and $0.6 million respectively. The amount expected to be expensed in the year ended December 31, 2015 has been recorded in Other Current Assets in the Partnership s

Consolidated Balance Sheet.

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11. Accrued Liabilities

	As of December 31,	
	2014	2013
Accrued product taxes	$ 18,248	$ 8,053
Customer prepayments and deposits	14,665	12,981
Accrued product costs	10,174	2,243
Accrued wages and benefits	6,389	7,735
Other	14,340	12,916
Accrued liabilities	$ 63,816	$ 43,928

12. Debt

	As of December 31,	
	2014	2013
Current debt		
Credit agreements	$ 396,961	$ 126,652
Credit agreement Canadian subsidiary		42,613
Other	253	218
Current debt	397,214	169,483
Long-term debt		
Credit agreements	417,789	332,848
Term loan Canadian subsidiary		68,000
Other	567	500
Long-term debt	418,356	401,348
Total debt	$ 815,570	$ 570,831

Credit Agreements

On December 9, 2014, in connection with the acquisition of Kildair, the Partnership entered into an amended and restated revolving credit agreement (the Credit Agreement) that will mature on December 9, 2019. The revolving credit facilities under the Credit Agreement contain, among other items, the following:

A U.S. dollar revolving working capital facility of up to $1.0 billion to be used for working capital loans and letters of credit in the principal amount equal to the lesser of Sprague s borrowing base and $1.0 billion;

A multicurrency revolving working capital facility of up to $120.0 million to be used by Sprague s Canadian subsidiaries for working capital loans and letters of credit in the principal amount equal to the lesser of Kildair s borrowing base and $120.0 million.

A revolving acquisition facility of up to $400.0 million to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to Sprague s current businesses; and,

Subject to certain conditions, the U.S. dollar or multicurrency revolving working capital facilities may be increased by $200.0 million. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

All obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

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

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

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

The 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. As of December 31, 2014, the Partnership was in compliance with these financial covenants.

Prior to December 9, 2014, the Partnership s revolving credit agreement had a maturity date of October 30, 2018, and was secured by substantially all of the Partnership s assets. This agreement included a $750.0 million working capital facility used to fund working capital and letters of credit and a $250.0 million acquisition facility. Borrowings under this agreement bore interest based on LIBOR, plus a specified margin, which was a function of the utilization of this agreement for the working capital facility and leverage ratio for the acquisition facility.

Prior to the IPO, the Predecessor s revolving credit agreement (the Predecessor Credit Agreement) was refinanced in May 2010 and has a maturity date of May 28, 2014. The Predecessor Credit Agreement was secured by substantially all of the Predecessor s assets and included a $625.0 million working capital facility used to fund working capital and letters of credit and a $175.0 million acquisition facility. Borrowings under the Predecessor Credit Agreement bore interest based on LIBOR, plus a specified margin, which is a function of the utilization of the Predecessor Credit Agreement.

As of December 31, 2014 and 2013, working capital facilities borrowings were $503.2 million and $351.6 million, respectively, and outstanding letters of credit were $120.2 million and $73.4 million, respectively. The working capital facilities are subject to borrowing base reporting and as of December 31, 2014 and 2013, had a borrowing base of $843.3 million and $573.8 million, respectively. As of December 31, 2014, excess availability under the working capital facility was $219.9 million.

As of December 31, 2014 and 2013, acquisition line borrowings were $311.6 million and $107.9 million, respectively. As of December 31, 2014, excess availability under the acquisition facility was $88.4 million.

The weighted average interest rate at December 31, 2014 and 2013 was 2.8% and 3.4%, respectively. The current portion of the credit agreement at December 31, 2014 and 2013 represents the amounts intended to be repaid during the following twelve month period.

The Credit Agreement contains certain restrictions and covenants among which are a minimum level of net working capital, fixed charge coverage and debt leverage ratios and limitations on the incurrence of indebtedness. The Credit

Agreement limits the Partnership s ability to make distributions in the event of defaults as defined in the Credit Agreement. As of December 31, 2014, the Partnership is in compliance with these financial covenants.

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Working Capital and Term Loan Credit Facility Canadian Subsidiary

The Partnership utilizes a credit facility in order to finance its operations, consisting of a working capital facility and term loan facility for a total amount of $210.0 ($120.0 of working capital facility and $90.0 of term loan) or the equivalent amount in Canadian dollars. The credit facility is guaranteed by Kildair s parent, and is secured by Kildair s assets, Kildair s parent s assets and the assets of companies under common control. The amount used as of December 31, 2013 is $110.6 with $42.6 of Working Capital loans and $68.0 of Term loan. The loans under the facility bear interest at either Prime / Base Rate plus a spread based on utilization or CDOR / Eurodollar rates plus a spread and matures in April 2015. The effective Canadian dollar borrowing rate is 5.13% at December 31, 2013.

The terms of the credit facility impose financial covenants including a minimum consolidated net working capital, a minimum consolidated fixed charge coverage ratio, a maximum consolidated secured leverage ratio, a limitation on capital expenditures. As of December 31, 2013, the Company was in compliance with the restrictive covenants.

This credit facility was retired in connection with the Partnership acquiring Kildair on December 9, 2014.

13. Related Party Transactions

The Parent charged the Predecessor $1.1 million for the period January 1, 2013 to October 29, 2013 and $1.3 million for the year ended December 31, 2012, for oversight and monitoring of the Predecessor. Such amounts are included in selling, general and administrative expenses in the Consolidated and Combined Statement of Operations. Intercompany activities are settled monthly and do not bear interest. There are no material intercompany accounts receivable or intercompany accounts payable balances outstanding with the Parent as of December 31, 2014. As of December 31, 2013, Kildair had notes payable to the Parent and an affiliate of the Parent of $17.5 million and $14.5 million, respectively. These notes payable were retired in connection with the Partnership acquiring Kildair on December 9, 2014.

For the period from January 1, 2013 to October 30, 2013 and for the years ended December 31, 2012, the Predecessor made cash distributions to the Parent of $40.0 million and $26.9 million, respectively, as permitted by the Predecessor Credit Agreement.

In connection with the IPO, the Predecessor distributed to Sprague Holdings, or its affiliates, certain assets and liabilities, including among others, its ownership of Kildair as well as accounts receivable of $130.2 million and cash of $10.0 million in an aggregate amount equal to the net proceeds of the IPO. On December 9, 2014, the Partnership acquired all of the equity interest in Kildair through the acquisition of the equity interests of Kildair s parent, Sprague Canadian Properties, LLC (see Note 1).

Through the General Partner, the Partnership participates in certain of the Parent s pension and other benefit plans (see Note 16) and the Predecessor also had a tax sharing agreement with the Parent (see Note 15).

During July 2013 the Predecessor received a capital contribution of $10.0 million from the Parent in connection with the acquisition of the oil terminal in Bridgeport, Connecticut (see Note 3).

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 $82.0 million for the year ended December 31, 2014 and $12.9 million for the period from October 30, 2013 through December 31, 2013. Prior to the IPO, these expenses were incurred directly by the Predecessor. Amounts due to the General Partner were $16.3

million and $4.8 million as of December 31, 2014 and 2013, respectively.

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14. Other Liabilities

	As of December 31,	
	2014	2013
Port Authority terminal obligations	$ 8,409	$ 9,012
Postretirement benefit obligations	4,360	4,742
Other	5,115	1,261
Other liabilities	$ 17,884	$ 15,015

The Port Authority terminal obligations represent long-term obligations of the Partnership to a third party that constructed dock facilities at the Partnership s Searsport, Maine terminal. These amounts will be repaid by future wharfage fees incurred by the Partnership for the use of these facilities. The short-term portion of these obligations of $0.6 million at December 31, 2014 and 2013 is included in accrued liabilities and represents an estimate of the expected future wharfage fees for the ensuing year. The Partnership has exclusive rights to the use of the dock facilities through a license and operating agreement (License Agreement), which expires in 2033. The License Agreement provides the Partnership the option to purchase the dock facilities at any time at an amount equal to the remaining license fees due. The related dock facilities assets are treated as a capital lease and are included in property, plant and equipment.

Postretirement benefit obligations are comprised of actuarially determined postretirement healthcare, life insurance and other postretirement benefits (see Note 16).

15. Income Taxes

Prior to the completion of the IPO, the Predecessor prepared its income tax provision as if it operated as a stand-alone taxpayer for all periods presented in accordance with a pre-existing tax sharing agreement between the Predecessor and the Parent. With the completion of the IPO on October 30, 2013, the Partnership is now treated as a pass-through entity for U.S. federal income tax purposes. As a result, all income, expenses, gains, losses and tax credits generated flow through to its owners and, accordingly, do not result in a provision for U.S. federal income taxes and certain state income taxes.

The Partnership is generally not subject to U.S. state and federal income tax, with the exception in certain domestic jurisdictions based on the Partnership s sourced taxable income. The Partnership s taxable income or loss, which may vary substantially from the net income or net loss reported in the Consolidated and Combined Statements of Operations, is includable in the U.S. federal and state income tax returns of each unitholder.

The income tax provision (benefit) attributable to operations is summarized as follows:

	For the Years Ended December 31,		
	2014	2013	2012
			Predecessor

Current						
U.S. federal income tax	$	95	$	8,572	$	2,272
State and local income taxes		1,499		3,063		1,273
Foreign income taxes		1,448		755		(952)
Total current income tax provision		3,042		12,390		2,593
Deferred						
U.S. federal income tax		(11)		(3,420)		(3,576)
State and local income taxes		1,618		(2,358)		(890)
Foreign income taxes		860		(2,353)		(923)
Total deferred income tax provision (benefit)		2,467		(8,131)		(5,389)
Total income tax provision (benefit)	$	5,509	$	4,259	$	(2,796)

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U.S. and international components of income (loss) before income taxes and equity in net loss of foreign affiliate were as follows:

	For the Years Ended December 31, 2014	2013	2012 Predecessor
U.S.	$ 120,470	$ (15,772)	$ (8,389)
Foreign	7,853	(9,807)	(6,229)
Total income (loss) before income taxes and equity in net loss of foreign affiliate	$ 128,323	$ (25,579)	$ (14,618)

Reconciliations of the statutory U.S. federal income tax to the effective income tax for operations are as follows:

	For the Years Ended December 31, 2014	2013	2012 Predecessor
Statutory U.S. federal income tax at 35%	$ 44,913	$ (8,951)	$ (5,116)
Partnership (income) losses not subject to tax	(42,843)	10,854	
State and local income taxes, net of federal tax	3,111	173	250
Foreign income taxes	328	1,520	(1,305)
Transaction costs		(55)	2,663
Other, including non-recurring items		718	712
Total income tax provision (benefit)	$ 5,509	$ 4,259	$ (2,796)

The components of the deferred tax assets (liabilities) are as follows:

	As of December 31, 2014	2013
Deferred tax assets (liabilities)		
Current		
Bad debts	$ 102	$ 37
Inventories	580	2,012
Compensation	108	138
Other	105	20
Current	895	2,207
Non-current		

Depreciation and amortization		(18,338)		(17,940)
Other temporary differences, net		2,946		2,935
Valuation allowance		(434)		(436)
Non-current		(15,826)		(15,441)
Net deferred tax (liabilities)	$	(14,931)	$	(13,234)

As of December 31, 2014, the Partnership had foreign net operating loss carryforwards of approximately $3.0 million, and foreign investment tax credit carryforwards of $1.2 million, all of which were generated in Canada and expire in 2033. The Partnership s foreign subsidiaries record investment tax credits under the deferral method.

The Predecessor was not a separate taxable entity for U.S. federal and certain state income tax purposes and its results are included in the consolidated U.S. federal and certain state income tax returns of Lexa International Corporation, which is the sole stockholder of the Parent. Income tax provisions and benefits, related tax payments, and current and deferred tax balances have been prepared as if the Predecessor operated as a stand-alone taxpayer for all periods presented in accordance with the tax sharing agreement between the Predecessor and the Parent. Under the tax sharing agreement, the Predecessor was obligated to pay U.S. federal and certain state taxes to the Parent. In the event that the Parent does not have a consolidated liability for U.S. federal or certain state taxes, the Predecessor was not obligated to pay the Parent for such taxes and all such amounts are reflected as capital contributions. For the period from January 1, 2013 through October 29, 2013 and the year ended December 31, 2012, the Predecessor received $8.8 million and $2.2 million, respectively, of non-cash capital contributions from its Parent under the tax sharing agreement.

The Predecessor s and Partnership s policy is to accrue interest and penalties on uncertain tax positions as a component of income tax expense. During the years ended December 31, 2014, 2013 and 2012, the interest and penalties recognized by the Predecessor and Partnership were immaterial. The Partnership and its subsidiaries are subject to examination by the Internal Revenue Service and certain states for the years ended December 31, 2014 and 2013.

As of December 31, 2014, the Partnership has not provided deferred Canadian withholding taxes on accumulated Canadian earnings of approximately $46.1 million for certain Canadian subsidiaries which are indefinitely reinvested outside the U.S. The unrecognized deferred withholding tax liability associated with these earnings is approximately $2.3 million at December 31, 2014.

16. Retirement Plans

Pension Plans

Through the General Partner, the Partnership participates in a noncontributory defined benefit pension plan, the Axel Johnson Inc. Retirement Plan (the Plan), sponsored by the Parent. Benefits under the Plan were frozen as of December 31, 2003, and are based on a participant s years of service and compensation through December 31, 2003. The Plan s assets are invested principally in equity and fixed income securities. The Parent s policy is to satisfy the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA).

Through the General Partner, the Partnership also participates in an unfunded pension plan, the Axel Johnson Inc. Retirement Restoration Plan, for employees whose benefits under the defined benefit pension plan were reduced due to limitations under U.S. federal tax laws. Benefits under this plan were frozen as of December 31, 2003.

Both the Plan and the Retirement Restoration Plan are administered by the Parent. The costs of these benefits are based on the Partnership s portion of the projected benefit obligations under these plans. Charges related to these employee benefit plans were $1.0 million, $1.7 million and $1.2 million during the years ended December 31, 2014, 2013 and 2012, respectively.

Eligible employees also receive a defined contribution retirement benefit generally equal to a defined percentage of their eligible compensation. This contribution by the Partnership to employee accounts in Axel Johnson Inc. s Thrift and Defined Contribution Plan is in addition to any Partnership match on 401(k) contributions that employees currently choose to make. The Partnership made total contributions to these plans of $3.5 million, $3.1 million and $3.1 million during the years ended December 31, 2014, 2013 and 2012, respectively.

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Other Postretirement Benefits

The Parent and some of its subsidiaries, which include the Partnership, have a number of health care and life insurance benefit plans covering eligible employees who reach retirement age while working for the Parent. The plans are not funded. In general, employees hired after December 31, 1990, are not eligible for postretirement health care benefits. The Partnership has recorded postretirement expense of $0.3 million, $0.4 million, and $0.5 million during the years ended December 31, 2014, 2013 and 2012, respectively, related to these plans.

17. Segment Reporting

The Partnership is a wholesale and commercial distributor engaged in the purchase, storage, distribution and sale of refined products and natural gas, and also provides storage and handling services for a broad range of materials. The Partnership has four reporting operating segments that comprise the structure used by the chief operating decision makers (CEO and CFO/COO) to make key operating decisions and assess performance. These segments are refined products, natural gas, materials handling and other activities. Segment information includes Kildair since the acquisition date of October 1, 2012.

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

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

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

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

The Partnership evaluates segment performance based on adjusted gross margin, which is net sales less cost of products sold (exclusive of depreciation and amortization) 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), before allocations of corporate, terminal and trucking operating costs, depreciation, amortization, and interest. 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.

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Summarized financial information for the Partnership s reportable segments for the years ended December 31 is presented in the table below:

	For the Years Ended December 31, 2014	2013	2012 Predecessor
		(in thousands)	
Net sales:			
Refined products	$ 4,650,871	$ 4,331,410	$ 3,757,859
Natural gas	359,984	304,843	242,006
Materials handling	37,776	28,446	32,536
Other operations	21,131	18,650	11,506
Net sales	$ 5,069,762	$ 4,683,349	$ 4,043,907
Adjusted gross margin (1):			
Refined products	$ 146,021	$ 114,744	$ 77,480
Natural gas	55,536	40,373	26,844
Materials handling	37,811	28,430	32,320
Other operations	5,599	5,547	2,788
Adjusted gross margin	244,967	189,094	139,432
Reconciliation to operating income (2):			
Add: unrealized gain (loss) on inventory (3)	11,070	(4,188)	(227)
Add: unrealized gain (loss) on natural gas transportation contracts (4)	58,694	(55,745)	(17,650)
Operating costs and expenses not allocated to operating segments:			
Operating expenses	(62,993)	(53,273)	(47,054)
Selling, general and administrative	(76,420)	(55,210)	(46,449)
Write-off of deferred offering costs			(8,931)
Depreciation and amortization	(17,625)	(16,515)	(11,665)
Operating income	157,693	4,163	7,456
Gain on acquisition of business			1,512
Other (expense) income	(288)	568	(160)
Interest income	569	604	534
Interest expense	(29,651)	(30,914)	(23,960)
Income tax (provision) benefit	(5,509)	(4,259)	2,796
Equity in net loss of foreign affiliate			(1,009)
Net income (loss)	$ 122,814	$ (29,838)	$ (12,831)

(1) Adjusted gross margin is a non-GAAP financial measure used by management and external users of the Partnership s consolidated financial statements to assess the Partnership s economic results of operations and its

market value reporting to lenders. The Partnership adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory and natural gas transportation contracts relating to the underlying commodity derivative hedges, 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 and the utilization of transportation contracts relating to those hedges is realized in net income (loss).

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

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

(4) The unrealized hedging (gain) loss on natural gas transportation contracts represents the Company s 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 income (loss).

The Partnership had no single customer whose revenue was greater than 10% of total net sales for the years ended December 31, 2014, 2013 and 2012, respectively. The Partnership s foreign sales, primarily sales of refined products, asphalt and natural gas to its customers in Canada, were $344.3 million, $286.6 million and $96.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Segment Assets

Due to the comingled 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.

Changes in the carrying amount of goodwill by segment were as follows:

	As of December 31, 2012	Other (1)	Distribution (2)	As of December 31, 2013	Metromedia Energy	As of December 31, 2014
Refined products	$ 38,145	$ (571)	$ (1,024)	$ 36,550	$	$ 36,550
Natural gas	4,383			4,383	14,243	18,626
Materials handling	7,150	(254)		6,896		6,896
Other	1,216			1,216		1,216
Total	$ 50,894	$ (825)	$ (1,024)	$ 49,045	$ 14,243	$ 63,288

(1) Reflects changes in the goodwill amounts resulting from foreign currency translation
(2) Reflects goodwill associated with assets that were contributed to an affiliate of Sprague Holdings in connection with the IPO

Long-lived Assets

Long-lived assets (exclusive of intangible and other assets, net, and goodwill) classified by geographic location are as follows:

	As of December 31, 2014	As of December 31, 2013
United States	$ 163,963	$ 116,807
Canada	86,163	81,669

Total	$ 250,126	$ 198,476

18. Financial Instruments and Off-Balance Sheet Risk
Cash, Cash Equivalents, Accounts Receivable and Debt

As of December 31, 2014 and December 31, 2013, the carrying amounts of cash, cash equivalents and accounts receivable approximated fair value because of the short maturity of these instruments. As of December 31, 2014 and December 31, 2013, the carrying value of the Partnership s debt approximated fair value due to the variable interest nature of these instruments.

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Derivative Instruments

The following table presents all financial assets and financial liabilities of the Partnership measured at fair value on a recurring basis as of December 31, 2014 and December 31, 2013:

	As of December 31, 2014			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity fixed forwards	$ 229,679	$	$ 229,679	$
Commodity swaps and options	74		74	
Commodity derivatives	229,753		229,753	
Interest rate swaps	137		137	
Total	$ 229,890	$	$ 229,890	$
Financial liabilities:				
Commodity exchange contracts	$ 97	$ 97	$	$
Commodity fixed forwards	80,080		80,080	
Commodity swaps and options	8,424		8,424	
Commodity derivatives	88,601	97	88,504	
Interest rate swaps	553		553	
Currency swaps	22		22	
Total	$ 89,176	$ 97	$ 89,079	$

	As of December 31, 2013			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity exchange contracts	$ 165	$ 165	$ 0	$
Commodity fixed forwards	64,729		64,729	

Commodity swaps and options		204				204		
Commodity derivatives		65,098		165		64,933		
Interest rate swaps								
Total	$	65,098	$	165	$	64,933	$	
Financial liabilities:								
Commodity fixed forwards	$	128,370	$		$	128,370	$	
Commodity swaps and options		198				198		
Commodity derivatives		128,568				128,568		
Interest rate swaps		2,388				2,388		
Total	$	130,956	$		$	130,956	$	

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The Partnership enters into derivative contracts with counterparties, some of which are subject to master netting arrangements, which allow net settlements under certain conditions. The Partnership presents derivatives at gross fair values in the 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 gross fair value of these financial instruments, was approximately $229.9 million at December 31, 2014. Information related to these offsetting arrangements as of December 31, 2014 and December 31, 2013 is as follows:

	As of December 31, 2014					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$ 229,753	$	$ 229,753	$ (4,831)	$ (2,417)	$ 222,505
Interest rate swap derivative assets	137		137			137
Fair value of derivative assets	$ 229,890	$	$ 229,890	$ (4,831)	$ (2,417)	$ 222,642
Commodity derivative liabilities	$ (88,601)	$	$ (88,601)	$ 4,831	$	$ (83,770)
Interest rate swap derivative liabilities	(553)		(553)			(553)
Currency swap derivative liabilities	(22)		(22)			(22)
Fair value of derivative liabilities	$ (89,176)	$	$ (89,176)	$ 4,831	$	$ (84,345)

	As of December 31, 2013					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$ 65,098	$	$ 65,098	$ (5,506)	$ (4)	$ 59,588
Fair value of derivative assets	$ 65,098	$	$ 65,098	$ (5,506)	$ (4)	$ 59,588
Commodity derivative liabilities	$ (128,568)	$	$ (128,568)	$ 5,506	$	$ (123,062)
Interest rate swap derivative liabilities	(2,388)		(2,388)			(2,388)

Fair value of derivative liabilities	$ (130,956)	$	$ (130,956)	$ 5,506	$	$ (125,450)

Commodity Derivatives

The following table presents total realized and unrealized (losses) and gains on derivative instruments utilized for commodity risk management purposes for the years ended December 31, 2014, 2013 and 2012. Such amounts are included in cost of products sold in the Consolidated and Combined Statements of Operations:

	2014	2013	2012 Predecessor
Refined products contracts	$ 159,751	$ (320)	$ (7,238)
Natural gas contracts	30,372	(76,707)	(19,580)
Total	$ 190,123	$ (77,027)	$ (26,818)

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Included in realized and unrealized (losses) gains on derivatives instruments above are realized and unrealized (losses) gains on discretionary trading activities as follows:

	2014	2013	2012 Predecessor
Refined products contracts	$	$ (1,232)	$ 2,317
Natural gas contracts			8
Total	$	$ (1,232)	$ 2,325

The following table presents the gross volume of commodity derivative instruments outstanding as of December 31, 2014 and 2013:

	As of December 31, 2014		As of December 31, 2013	
	Refined Products (Barrels)	Natural Gas (MMBTUs)	Refined Products (Barrels)	Natural Gas (MMBTUs)
Long contracts	10,823	131,376	9,250	100,119
Short contracts	(15,434)	(82,796)	(12,677)	(74,265)

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.

At December 31, 2014, the Partnership held three interest rate swap agreements with a notional value of $100.0 million with swap periods that expire in January 2015. In addition, the Partnership held six interest rate swaps with a total notional value of $175.0 million whose swap periods begin in January 2015, expiring in January 2016; and five interest rate swaps with a total notional value of $150.0 million whose swap periods begin in January 2016, expiring in January 2017.

There was no material ineffectiveness determined for the cash flow hedges for the years ended December 31, 2014, 2013 and 2012.

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 December 31, 2014, the amount of unrealized losses, net of tax, expected to be reclassified to earnings during the following twelve-month period was $0.2 million.

The following table presents the location of the gains and losses on derivative contracts designated as cash flow hedging instruments reported in the Consolidated and Combined Statements of Comprehensive Income (Loss) as other comprehensive income (OCI) or other comprehensive loss (OCL) for the years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31, 2014	
	Amount of Derivative Loss Recognized in OCI	Amount of Derivative Loss Reclassified From Accumulated OCL Into Income
Interest rate swaps	$ 531	$ 2,501

	For the Year Ended December 31, 2013	
	Amount of Derivative Loss Recognized in OCL	Amount of Derivative Loss Reclassified From Accumulated OCL Into Income
Interest rate swaps	$ 376	$ 5,121

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	Predecessor For the Year Ended December 31, 2012	
	Amount of Derivative Loss Recognized in OCI	Amount of Derivative Loss Reclassified From Accumulated OCL Into Income
Interest rate swaps	$ 1,815	$ 4,144

Currency Derivatives

Our Canadian subsidiary enters into forward currency contracts to manage the risk of currency rate fluctuations between its dollar denominated activity and the U.S. dollar, which is its functional currency. At December 31, 2014, our Canadian subsidiary has entered into a series of forward currency swaps that mature through January 2015. The contracts obligate our Canadian subsidiary to purchase approximately $10.0 million in Canadian dollars at an exchange rate of 1.1631. The Canadian to U.S. dollar exchange rate was 1.1601 at December 31, 2014.

19. Commitments and Contingencies

Capital Leases

The Partnership holds leases for office and warehouse space, dock facilities, transportation equipment and other equipment, several of which are recorded as capital leases. At December 31, 2014 and 2013, the Partnership had short-term capital lease obligations of $1.3 million and $0.7 million, respectively, and long-term capital lease obligations of $5.4 million and $4.9 million, respectively. These balances exclude the obligations related to its Searsport, Maine terminal (see Note 14). Capital lease repayments are due as follows:

2015	$ 1,723
2016	1,677
2017	1,298
2018	924
2019	582
Thereafter	2,237
Total	8,441
Less amounts representing interest at rates between 3.7% and 8.3%	(1,704)
Present value of net minimum capital lease payments	$ 6,737

Operating Leases

The Partnership has leases for a refined products terminal, refined products storage, maritime charters, office and plant facilities, computer and other equipment for periods extending to 2034. Renewal options exist for a substantial portion of these leases. For operating leases, rental expense was $17.4 million, $11.8 million and $10.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following table summarizes the future annual payments for operating leases as of December 31, 2014:

2015	$ 14,224
2016	14,344
2017	11,629
2018	8,821
2019	3,962
Thereafter	6,452
Total	$ 59,432

Legal, Environmental and Other Proceedings

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

20. Offering Costs Initial Public Offering

During 2012 and 2011, the Predecessor had accumulated certain costs related to efforts to complete an initial public offering of limited partnership units. During the year ended December 31, 2012, the Predecessor delayed the plan for this public offering and as a result, accumulated deferred offering costs of $8.9 million were charged against earnings.

During 2013, the Partnership incurred offering costs of $12.7 million for the period January 1, 2013 through October 30, 2013 that were charged directly to equity upon completion of the IPO on October 30, 2013.

21. Equity-Based Compensation

During the fiscal year ended December 31, 2013, the board of directors of the General Partner issued a total of 6,666 restricted unit awards (estimated grant date fair value of $0.1 million) to certain directors under the Sprague Resources 2013 Long-Term Incentive Plan (the 2013 LTIP). Recipients have both voting rights and distribution rights on any unvested units. The fair value of each restricted unit on the grant date is equal to the market price of the Partnership s common unit on that date. The estimated fair value of the restricted units is amortized over the vesting period using the straight-line method. Total unrecognized compensation cost related to the nonvested restricted units was less than $0.1 million as of December 31, 2014, which is expected to be recognized over a period of approximately 22 months.

On March 31, 2014, the board of directors of the General Partner granted 49,871 awards under the 2013 LTIP to certain directors and employees of the Partnership. Of these total awards, 26,186 (estimated grant date fair value of $0.5 million) were granted as vested common units. In connection with these vested awards, the Partnership reacquired from the recipients 6,768 units (estimated fair value of $0.1 million) to satisfy minimum tax withholding obligations. The remaining 23,685 awards (estimated grant date fair value of $0.5 million), consisted of phantom units issued to employees that are expected to vest as follows: 13,766 units on March 31, 2015 and 9,919 on March 31, 2016. The grant date fair value of these awards is equal to the market price of the Partnership s common unit on that date. Total unrecognized compensation related to phantom units was $0.3 million as of December 31, 2014 which is expected to be recognized over a period of approximately 15 months. Recipients have distribution rights on any unvested phantom units.

On July 11, 2014, the Board of Directors of the General Partner approved under the 2013 LTIP the 2014 annual bonus program which is provided to substantially all employees and will be settled in cash for the majority of participants with others receiving a combination of cash and common units. In previous years all participants were compensated only in cash. The Partnership records the entire expected bonus payment as a liability until a grant date has been established and awards finalized, which occurs in the first quarter of the following year. Subsequent to December 31, 2014 approximately $4.6 million of the annual bonus expense recorded during the year ended December 31, 2014 was settled in units.

On July 11, 2014, the Board of Directors of the General Partner granted under the 2013 LTIP performance-based phantom unit awards to key employees; previously this long-term incentive program was settled solely in cash. These units vest over a three year period if certain performance criteria are met. Upon vesting, a holder of performance-based phantom units is entitled to receive a number of common units of the Partnership equal to a percentage (0 percent to 200 percent) of the target phantom units granted, based on the Partnership s total unitholder return over the vesting period, compared with the total unitholder return of a peer group of other

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master limited partnership energy companies over the same period. The Partnership has performed this calculation as of December 31, 2014 and has determined that performance-based phantom units vesting as of December 31, 2014 will be exchanged into common units using a 200% factor and as a result, 74,048 common units were issued subsequent to year-end.

The Partnership s performance-based phantom unit awards are equity awards with both service and market-based conditions, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market based conditions are satisfied. The fair value of these performance-based phantom units granted on July 11, 2014 was estimated to be $5.5 million (or a weighted average of $36.88 per unit) based on a Monte Carlo model that estimated the most likely outcome based on the terms of the award. The key inputs in the model include the market price of the Partnership s common units as of the valuation date, the historical volatility of the market price of the Partnership s common units, the historical volatility of the market price of the common units or common stock of the peer companies and the correlation between changes in the market price of the Partnership s common units and those of the peer companies. As part of the Monte Carlo simulation, 100,000 simulations were performed using a weighted average volatility of 26.4% , and a weighted average risk free rate of .43%. Total unrecognized compensation cost related to the performance-based phantom units totaled $2.5 million as of December 31, 2014, which is expected to be recognized over a period of approximately 24 months. Performance-based phantom units accrue dividend equivalents which are recorded as liabilities over the requisite service period and are paid in cash upon vesting of the underlying performance-based phantom unit.

On October 15, 2014, the board of directors of the General Partner issued a total of 7,983 fully vested restricted unit awards (estimated grant date fair value of $0.2 million) to certain directors under the 2013 LTIP.

A summary of the Partnership s unit awards subject to vesting for the year ended December 31, 2014, is set forth below:

	Restricted Units		**Phantom Units**		**Performance Based Phantom Units**	
	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, 2013	6,666	$ 17.33		$		$
Granted			23,685	20.16	151,099	36.88
Forfeiture					(3,000)	(36.88)
Vested	(2,222)	(17.33)			(37,024)	(36.88)
Nonvested at December 31, 2014	4,444	$ 17.33	23,685	$ 20.16	111,075	$ 36.88

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

	Common Units		
	Public	Sprague Holdings	Subordinated Units
Balance as of October 29, 2013			
Units issued in connection with initial public offering	8,500,000	1,571,970	10,071,970
Restricted unit awards	6,666		
Balance as of December 31, 2013	8,506,666	1,571,970	10,071,970
Employee and Director vested awards	27,401		
Units issued in connection with Castle acquisition	243,855		
Units issued in connection with Kildair acquisition		462,408	
Balance as of December 31, 2014	8,777,922	2,034,378	10,071,970

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Unit-based compensation recorded in unitholders equity for the year ended December 31, 2014 and 2013 was $3.6 million and less than $0.1 million, respectively, and is included in selling, general and administrative expenses. Units issued under the Partnership s 2013 LTIP are newly issued.

22. Earnings Per Unit Calculation

Earnings per unit applicable to limited partners (including subordinated unitholders) is computed by dividing limited partners interest in net income (loss), after deducting any incentive distributions, by the weighted-average number of outstanding common and subordinated units. The Partnership s net income (loss) is allocated to the limited partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to Sprague Holdings, the holder of the IDRs, pursuant to the partnership agreement, which are declared and paid following the close of each quarter. Earnings (losses) per unit is only calculated for the Partnership after the IPO as no units were outstanding prior to October 30, 2013. Earnings in excess of distributions are allocated to the limited partners based on their respective ownership interests. Payments made to the Partnership s unitholders are determined in relation to actual distributions declared and are not based on the net income (loss) allocations used in the calculation of earnings per unit.

In addition to the common and subordinated units, the Partnership has also identified the IDRs and unvested restricted units as participating securities and uses the two-class method when calculating the net income (loss) per unit applicable to limited partners, which is based on the weighted-average number of common units outstanding during the period. Diluted earnings per unit includes the effects of potentially dilutive units on the Partnership s common units, consisting of unvested restricted units. For the period from October 30, 2013 through December 31, 2013 basic and diluted earnings per unit applicable to common limited partners are the same because including the effect of unvested restricted units would have been anti-dilutive. Basic and diluted earnings (losses) per unit applicable to subordinated limited partners are the same because there are no potentially dilutive subordinated units outstanding.

The table below shows the weighted average common units outstanding used to compute net income (loss) per common unit for the years ended December 31, 2014 and 2013.

	2014	2013
Weighted average limited partner common units basic	10,131,928	10,071,970
Dilutive effect of unvested restricted and phantom units	63,638	
Weighted average limited partner common units diluted	10,195,566	10,071,970

The following table presents the Partnership s basic earnings (loss) per common and subordinated unit for the years ended December 31, 2014 and 2013.

	For the Year Ended December 31, 2014		
	Common Units	Subordinated Units	Total
	(in thousands, except for per unit amounts)		

Limited partners interest in net income			$ 118,734
Distributions declared	$ 17,964	$ 17,526	$ 35,490
Assumed net income from operations after distributions	41,579	41,665	83,244
Assumed net income to be allocated	$ 59,543	$ 59,191	$ 118,734
Earnings per unit basic	$ 5.88	$ 5.88	
Earnings per unit diluted	$ 5.84	$ 5.88	

	For the Year Ended December 31, 2013		
	Common Units	Subordinated Units	Total
	(in thousands, except for per unit amounts)		
Limited partners interest in net loss			$ (30,234)
Distributions declared	$ 2,846	$ 2,846	$ 5,692
Assumed net loss from operations after distributions	(17,963)	(17,963)	(35,926)
Assumed net loss to be allocated	$ (15,117)	$ (15,117)	$ (30,234)
Earnings per unit basic	$ (1.50)	$ (1.50)	
Earnings per unit diluted	$ (1.50)	$ (1.50)	

23. Quarterly Financial Data (Unaudited)

Unaudited quarterly financial data is as follows:

	For the Year Ended December 31, 2014 (1)				
	First	Second	Third	Fourth	Total
	(in thousands, except for per unit amounts)				
Net sales	$ 1,994,699	$ 979,661	$ 897,408	$ 1,197,994	$ 5,069,762
Net income (loss)	73,132	(10,604)	(5,302)	65,588	122,814
Limited Partners interest in net income (loss)	$ 75,335	(9,494)	(10,718)	63,611	118,734
Net income (loss) per limited partner unit: (3,4)					
Common (basic)	$ 3.74	$ (0.47)	$ (0.53)	$ 3.13	$ 5.88
Common (diluted)	$ 3.74	$ (0.47)	$ (0.53)	$ 3.07	5.84
Subordinated (basic and diluted)	$ 3.74	$ (0.47)	$ (0.53)	$ 3.13	$ 5.88

	For the Year Ended December 31, 2013 (1)				
	First	Second	Third	Fourth (2)	Total
	(in thousands, except for per unit amounts)				
Net sales	$ 1,544,953	$ 921,820	$ 940,275	$ 1,276,301	$ 4,683,349
Net income (loss)	14,334	(2,719)	(6,411)	(35,042)	(29,838)
Limited partners interest in net loss from October 30, 2013 to December 31, 2013				(30,234)	(30,234)
Net loss per limited partner unit (3)					
Common (basic and diluted)				$ (1.50)	$ (1.50)
Subordinated (basic and diluted)				$ (1.50)	$ (1.50)

(1) As discussed in Note 1, the Consolidated and Combined Financial Statements for periods prior to December 9, 2014 have been recast to include Kildair. The quarterly net sales and net income (loss) presented above has also

been recast accordingly.

(2) Includes the results of operations of the Predecessor through October 29, 2013 and the Partnership for the period October 30, 2013 through December 31, 2013.

(3) Net loss per unit is only calculated for the Partnership after the IPO as no units were outstanding prior to October 30, 2013.

(4) Quarterly net income per limited partner unit amounts are stand-alone calculations and may not be additive to full year amounts due to rounding and changes in outstanding units.

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24. Partnership Distributions

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

On January 29, 2014, the Partnership declared a cash distribution totaling $5.7 million, or $0.2825 per unit with respect to the quarter ended December 31, 2013. Such cash distribution was calculated as the minimum quarterly cash distribution of $0.4125 per unit prorated for the period beginning October 30, 2013, the IPO closing date through December 31, 2013. Such distribution was paid on February 14, 2014 to unitholders of record on February 10, 2014.

On April 29, 2014, the Partnership declared a cash distribution totaling $8.3 million, or $0.4125 per unit for the three months ended March 31, 2014. Such distribution was paid on May 15, 2014, to unitholders of record on May 9, 2014.

On July 29, 2014, the Partnership declared a cash distribution totaling $8.6 million, or $0.4275 per unit for the three months ended June 30, 2014. Such distribution was paid on August 14, 2014, to unitholders of record on August 8, 2014.

On October 29, 2014 the Partnership declared a cash distribution totaling $8.9 million, or $0.4425 per unit for the three months ended September 30, 2014. Such distribution was paid on November 14, 2014, to unitholders of record on November 10, 2014.

25. Subsequent Event

Partnership distributions

On January 28, 2015 the Partnership declared a cash distribution totaling $9.6 million, or $0.4575 per unit for the three months ended December 31, 2014. Such distribution was paid on February 13, 2015, to unitholders of record on February 9, 2015.

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EXHIBIT INDEX

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

Exhibit No.	Description
2.1***	Asset Purchase Agreement, dated September 10, 2014, by and among Sprague Operating Resources LLC, Metromedia Gas & Power, Inc., Metromedia Gas LLC, Metromedia Energy, Inc., EnergyEXPRESS, Inc. and Metromedia Power, Inc. (incorporated by reference to Exhibit 2.1 of Sprague Resources LP s Current Report on Form 8-K filed September 11, 2014 (File No. 001-36137)).
2.2***	Asset Purchase Agreement, dated November 4, 2014, by and among Sprague Operating Resources LLC, Castle Oil Corporation, Castle Port Morris Terminals, Inc., Castle Energy Solutions, LLC, Castle Fuels Corporation, Castle Supply & Marketing, Inc. and Castle Energy Solutions S.B., LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2014 (File No. 001-36137)).
2.3	Purchase Agreement, dated December 9, 2014, by and among Sprague Resources ULC, Sprague International Properties LLC, Sprague Canadian Properties LLC and Axel Johnson Inc. (incorporated by reference to Exhibit 2.1 of Sprague Resources LP s Current Report on Form 8-K filed December 12, 2014 (File No. 001-36137)).
2.4	Consideration Agreement, dated December 9, 2014, between Sprague Resources LP and Sprague Resources ULC (incorporated by reference to Exhibit 2.2 of Sprague Resources LP s Current Report on Form 8-K filed December 12, 2014 (File No. 001-36137)).
3.1	First Amended and Restated Agreement of Limited Partnership of Sprague Resources LP (incorporated by reference to Exhibit 3.1 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
3.2	First Amended and Restated Limited Liability Company Agreement of Sprague Resources GP LLC (incorporated by reference to Exhibit 3.2 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.1	Amended and Restated Credit Agreement among Sprague Operating Resources LLC, as U.S. borrower, Sprague Resources ULC and Kildair Service Ltd., as initial Canadian borrowers, the several lenders parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian agent, and the co-collateral agents, the co-syndication agents and the co-documentation agents party thereto (incorporated by reference to Exhibit 10.1 of Sprague Resources LP s Current Report on Form 8-K filed December 12, 2014 (File No. 001-36137)).
10.2	Contribution, Conveyance and Assumption Agreement by and among Sprague Resources LP, Sprague Resources GP LLC, Axel Johnson Inc., Sprague International Properties LLC, Sprague Canadian Properties LLC, Sprague Resources Holdings LLC, Sprague Massachusetts Properties LLC and Sprague Operating Resources LLC (incorporated by reference to Exhibit 10.2 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).

10.3	Omnibus Agreement by and among Axel Johnson Inc., Sprague Resources Holdings LLC, Sprague Resources LP and Sprague Resources GP LLC (incorporated by reference to Exhibit 10.3 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.4	Services Agreement by and among Sprague Resources GP LLC, Sprague Resources LP, Sprague Resources Holdings LLC and Sprague Energy Solutions Inc. (incorporated by reference to Exhibit 10.4 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.5	Terminal Operating Agreement by and between Sprague Massachusetts Properties LLC and Sprague Operating Resources LLC (incorporated by reference to Exhibit 10.5 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).

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Exhibit No.	Description
10.6	Sprague Resources LP 2013 Long-Term Incentive Plan, effective as of October 28, 2013 (incorporated by reference to Exhibit 4.4 to Sprague Resources LP s Registration Statement on Form S-8, filed on October 25, 2013 (File No. 333-191923)).
10.7	Form of Phantom Unit Award Agreement (incorporated by reference to Exhibit 10.8 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).
10.8	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.9 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).
10.9	Form of Unit Award Letter (incorporated by reference to Exhibit 10.10 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).
10.10	Form of Phantom Unit Agreement (Performance Based Vesting) (incorporated by reference to Exhibit 10.1 of Sprague Resources LP s Current Report on Form 8-K filed on August 13, 2014 (File No. 001-36137)).
10.11	Director Compensation Summary (incorporated by reference to Exhibit 10.1 of Sprague Resources LP s Current Report on Form 8-K filed on October 17, 2014 (File No. 001-36137)).
10.12	Unit Purchase Agreement, dated November 4, 2014, by and between Sprague Resources LP and Castle Oil Corporation, dated November 4, 2014 (incorporated by reference to Exhibit 10.1 of Sprague Resources LP s Current Report on Form 8-K filed November 5, 2014 (File No. 001-36137)).
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Ernst & Young LLP
31.1*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Executive Officer.
31.2*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Financial Officer.
32.1**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation

Compensatory plan or arrangement.

* 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.