Crestwood Equity Partners LP
Form 10-K
March 02, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ý 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: 001-34664
Crestwood Equity Partners LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	43-1918951 (I.R.S. Employer Identification No.)
700 Louisiana Street, Suite 2550 Houston, Texas (Address of principal executive offices)	77002 (Zip code)

(832) 519-2200
(Registrant’s telephone number, including area code)

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 partnership interests	The New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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 on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
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 Act). Yes ¨ No x

The aggregate market value of the 111,166,893 common units of the registrant held by non-affiliates computed by reference to the $7.09 closing price of such common units on February 13, 2015, was $0.8 billion. As of June 30, 2014, the last business day of the registrant's most recently completed second quarter, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was $1.6 billion based on a closing price of $14.87 per common unit as reported on the New York Stock Exchange on such date. As of February 13, 2015, the registrant had 187,349,776 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents are incorporated by reference into the indicated parts of this report: None.

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GLOSSARY

The terms below are common to our industry and used throughout this report.

/d	per day
AOD	Area of dedication, which means the acreage dedicated to a company by an oil and/or natural gas producer under one or more contracts.
ASC	Accounting Standards Codification.
Barrel (Bbl)	One barrel of petroleum products equal to 42 U.S. gallons.
Base gas	A quantity of natural gas held within the confines of the natural gas storage facility and used for pressure support and to maintain a minimum facility pressure. May consist of injected base gas or native base gas. Also known as cushion gas.
Bcf	One billion cubic feet of natural gas. A standard volume measure of natural gas products.
Cycle	A complete withdrawal and injection of working gas. Cycling refers to the process of completing one cycle.
Dth	One dekatherm of natural gas.
EPA	Environmental Protection Agency.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
Firm service	Services pursuant to which customers receive an assured or firm right to (i) in the context of storage service, store product in the storage facility or (ii) in the context of transportation service, transport product through a pipeline, over a defined period of time.
GAAP	Generally Accepted Accounting Principles.
Gas storage capacity	The maximum volume of natural gas that can be cost-effectively injected into a storage facility and extracted during the normal operation of the storage facility. Gas storage capacity excludes base gas.
G&P	Gathering and processing.
Hub	Geographic location of a storage facility and multiple pipeline interconnections.
Hub services	With respect to our natural gas storage and transportation operations, the following services: (i) interruptible storage services, (ii) firm and interruptible park and loan services, (iii) interruptible wheeling services, and (iv) balancing services.
Injection rate	The rate at which a customer is permitted to inject natural gas into a natural gas storage facility.
Interruptible service	Services pursuant to which customers receive only limited assurances regarding the availability of (i) with respect to storage services, capacity and deliverability in storage facilities or (ii) with respect to transportation services, capacity and deliverability from receipt points to delivery points. Customers pay fees for interruptible services based on their actual utilization of the storage or transportation assets.
LIBOR	London Interbank Offered Rate.
MMbtu	One million British thermal units, which is approximately equal to one Mcf. One British thermal unit is equivalent to an amount of heat required to raise the temperature of one pound of water by one degree.
MMcf	One million cubic feet of natural gas.
Natural gas	A gaseous mixture of hydrocarbon compounds, primarily methane together with varying quantities of ethane, propane, butane and other gases.
Natural Gas Act	Federal law enacted in 1938 that established the FERC's authority to regulate interstate pipelines.
Natural gas liquids (NGLs)	

	Those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. NGLs include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).
NYSE	New York Stock Exchange.
Salt cavern	A man-made cavern developed in a salt dome or salt beds by leaching or mining of the salt.
SEC	Securities and Exchange Commission.

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Wheeling	The transportation of natural gas from one pipeline to another pipeline through the pipeline facilities of a natural gas storage facility. The gas does not flow into or out of actual storage, but merely uses the surface facilities of the storage operation.
Withdrawal rate	The rate at which a customer is permitted to withdraw gas from a natural gas storage facility.
Working gas	Natural gas in a storage facility in excess of base gas. Working gas may or may not be completely withdrawn during any particular withdrawal season.
Working gas storage capacity	See gas storage capacity (above).

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PART I

Item 1. Business.

Unless the context requires otherwise, references to (i) "we," "us," "our," "ours," "our company," the "Company," the "Partner "Crestwood Equity," and similar terms refer to either Crestwood Equity Partners LP itself or Crestwood Equity Partners LP and its consolidated subsidiaries, as the context requires, (ii) "Crestwood Midstream" refers to Crestwood Midstream Partners LP and its consolidated subsidiaries following the Crestwood Merger (defined below), (iii) "Legacy Inergy" refers to Inergy, L.P. and its consolidated subsidiaries prior to the Crestwood Merger, (iii) "Inergy Midstream" refers to Inergy Midstream, L.P. and its consolidated subsidiaries prior to the Crestwood Merger, and (iv) "Legacy Crestwood" refers to Crestwood Midstream Partners LP and its consolidated subsidiaries prior to the Crestwood Merger. Unless otherwise indicated, information contained herein is reported as of December 31, 2014.

Introduction

Crestwood Equity, a Delaware limited partnership formed in 2004, is a master limited partnership (MLP) that develops, acquires, owns or controls, and operates primarily fee-based assets and operations within the energy midstream sector. Headquartered in Houston, Texas, we provide broad-ranging infrastructure solutions across the value chain to service premier liquids-rich and crude oil shale plays across the United States. Our common units representing limited partner interests are listed on the NYSE under the symbol "CEQP."

We own and operate a diversified portfolio of crude oil and natural gas gathering, processing, storage and transportation assets that connect fundamental energy supply with energy demand across North America. Our consolidated operating assets include:

- natural gas facilities with approximately 2.5 Bcf/d of gathering capacity, 481 MMcf/d of processing capacity, 1.1 Bcf/d of firm transmission capacity, and 41 Bcf of certificated working gas storage capacity;

- NGL facilities with approximately 24,000 Bbls/d of fractionation capacity and 2.8 million barrels of storage capacity;

- crude oil facilities with approximately 125,000 Bbls/d of gathering capacity, approximately 1.1 million barrels of storage capacity, 48,000 Bbls/d of transportation capacity and 160,000 Bbls/d of rail loading capacity; and

- a fleet of transportation assets supporting our proprietary NGL supply and logistics business, including 8 truck and rail terminals and approximately 543 truck/trailer units and 1,600 rail units that can transport more than 294,000 Bbls/d of NGLs.

Our primary business objective is to increase the cash distributions that we pay to our unitholders. We have worked to position Crestwood Midstream as a growth MLP through which we will expand our midstream platform and to reposition the Company as more of a "pure play" general partner rather than an operating company, and we expect to continue this strategy going forward. We therefore expect to increase cash available for distribution to our unitholders primarily through our investment in Crestwood Midstream and, to a lesser extent, through growth opportunities involving the assets owned by us. We anticipate that the contribution of our remaining operating assets into Crestwood Midstream will enhance our value based on our ownership interests in Crestwood Midstream (including our ownership of its incentive distribution rights or IDRs), and we expect to consummate such drop downs at an appropriate time in the future.

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Ownership Structure

The diagram below reflects a simplified version of our ownership structure as of December 31, 2014:

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Our non-economic general partner interest is held by Crestwood Equity GP LLC, our general partner and which is indirectly owned by Crestwood Holdings LLC (Crestwood Holdings). Crestwood Holdings, which is substantially owned and controlled by First Reserve Management, L.P. (First Reserve), also owns approximately 27% of our limited partner units as of December 31, 2014.

We own the non-economic general partner interest of Crestwood Midstream and, therefore, control and consolidate Crestwood Midstream. We also own 100% of the IDRs and approximately 4% of the common units representing limited partnership interests of Crestwood Midstream as of December 31, 2014.

In May 2013, the former owners of our general partner and Crestwood Holdings entered into a series of transactions that would effectively consolidate and combine the operations of Legacy Crestwood and Legacy Inergy. The parties first completed a series of “upstairs” transactions in June 2013 that resulted in Crestwood Holdings’ acquisition of control of us. The strategic business combination was completed in October 2013 when Legacy Crestwood merged with and into Inergy Midstream (the Crestwood Merger) and Inergy Midstream changed its name to Crestwood Midstream Partners LP. See Part IV, Item 15, Exhibits, Financial Statement Schedules, Notes 1 and 3 for additional information on these related transactions.

Our Assets

We, through our wholly-owned subsidiaries, own and operate a proprietary NGL supply and logistics business, which includes our West Coast NGL operations, our Seymour NGL storage facility and our fleet of NGL transportation and related rail-to-truck terminal assets. All of our other consolidated assets are owned by or through Crestwood Midstream.

We have three reporting segments: (i) gathering and processing (G&P), (ii) storage and transportation, and (iii) NGL and crude services.

Gathering and Processing

We provide natural gas gathering, processing, treating and compression services to producers in multiple unconventional shale plays located in West Virginia, Wyoming, Texas, Arkansas, New Mexico, and Louisiana. We own rich gas systems in the Marcellus, Barnett, Granite Wash, Avalon/Bone Spring and Powder River Basin (PRB) Niobrara Shale plays, as well as dry gas gathering systems in the Barnett, Fayetteville and Haynesville/Bossier Shale plays.

The table below summarizes certain information about our G&P systems (including our equity investment) as of December 31, 2014:

Shale Play (State)	Counties / Parishes	Pipeline (Miles)	Gathering Capacity (MMcf/d)	Average Gathering Volume (MMcf/d)	Compression (HP)	Number of In-Service Processing Plants	Processing Capacity (MMcf/d)	Gross Acreage Dedication
Marcellus West Virginia	Harrison, Barbour and Doddridge	77	875	598	138,080	—	—	140,000
Barnett Texas	Hood, Somervell, Johnson, Tarrant, and Denton	496	955	417	153,465	2	425	140,000

Fayetteville Arkansas	Conway, Faulkner, Van Buren, and White	171	510	98	27,645	—	—	143,000
Granite Wash Texas	Roberts	36	36	23	12,240	1	36	22,000
Haynesville / Bossier Louisiana	Sabine	57	100	9	—	—	—	22,000
Avalon / Bone Spring New Mexico	Eddy	71	50	13	955	1	20	107,000
Consolidated Total		908	2,526	1,158	332,385	4	481	574,000
PRB Niobrara(1) Wyoming	Converse	162	90	56	24,080	—	—	311,000
Total		1,070	2,616	1,214	356,465	4	481	885,000

(1) Our PRB Niobrara assets are owned by Jackalope Gas Gathering Services, L.L.C. (Jackalope), our 50% equity method investment.

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We generate G&P revenues predominantly under fee-based contracts, which minimizes our commodity price exposure and provides less volatile operating performance and cash flows. Our principal G&P systems are described below.

Marcellus

We own and operate rich gas systems in Harrison and Doddridge Counties, West Virginia and a dry gas system in Barbour County, West Virginia. These systems consist of 77 miles of low pressure gathering lines and eight compression and dehydrations stations with 138,080 horsepower. Our current operations are predominantly focused on our rich gas systems. On these systems, we provide midstream services to Antero Resources Appalachian Corporation (Antero), which is the most active upstream developer of the rich gas corridor of the southwestern core of the Marcellus Shale play. We provide our services under long-term, fixed-fee contracts across two operating areas, our eastern area of operation (East AOD) and our western area of operation (Western Area).

In the East AOD, we provide gathering, dehydration and compression services to Antero in an approximately 140,000 gross acre area from which Antero has dedicated all production of rich natural gas to our system pursuant to a 20-year, fixed-fee gathering and compression agreement. As a part of that agreement, we gather and deliver Antero's production to MarkWest Energy Partners' Sherwood Gas Processing Plant and various regional pipeline systems. Our system is currently connected to 225 wells and current average daily volumes delivered to our system have increased by over 180% from when we acquired the assets in 2012.

In the Western Area, we provide compression and dehydration services to Antero's gathering facilities predominantly with our West Union and Victoria compressor stations. We provide services to Antero under a seven year, fixed-fee agreement that runs through 2021, subject to Antero's right to extend the contract term for an additional three years. Although volumes compressed from these stations are not contractually dedicated to us in the Western Area, Antero does provide minimum volume commitments up to 50% of the throughput capacity of each compressor station. We also hold a right of first offer until 2019 to acquire and develop any midstream facilities developed by Antero in the Western Area for ultimate transfer or sale to a third party.

In the southwest portion of the Marcellus Shale, we have completed several expansions on our Antero gathering system that have increased total gathering capacity. Antero continues to develop production in the Marcellus Shale to connect additional wells to our systems. We invested approximately $191 million in our Marcellus systems during the year ended December 31, 2014.

Barnett

We own and operate three systems in the Barnett Shale, including the Cowtown, Lake Arlington and the Alliance systems.

Our Cowtown system, which is located principally in the southern portion of the Fort Worth Basin, consists of (i) pipelines that gather rich natural gas produced by customers and deliver the volumes to our plants for processing, (ii) the Cowtown plant, which includes two natural gas processing units that extract NGLs from the natural gas stream and deliver customers' residue gas and extracted NGLs to unaffiliated pipelines for sale downstream, and (iii) the Corvette plant, which extracts NGLs from the natural gas stream and delivers customers' residue gas and extracted NGLs to unaffiliated pipelines for sale downstream. For the year ended December 31, 2014, our Cowtown and Corvette plants had a total average throughput of 170 MMcf/d of natural gas with an average NGL recovery of 15,600 Bbl/d.

Our Lake Arlington system, which is located in eastern Tarrant County, Texas, consists of a gas gathering system and related dehydration and compression facilities. Our Alliance system, which is located in northern Tarrant and southern Denton Counties, Texas, consists of a gas gathering system and a related dehydration, compression and amine treating facility.

We also own the West Johnson County system in the Barnett, which was operational from the date we acquired the plant (August 24, 2012) until we ceased operating the plant on December 31, 2012. We have since diverted rich gas volumes to our other processing facilities and are currently evaluating other potential uses for the West Johnson County plant, which has a processing capacity of 100 MMcf/d of natural gas.

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Fayetteville

We own and operate five systems in the Fayetteville Shale, including the Twin Groves, Prairie Creek, Woolly Hollow, Wilson Creek, and Rose Bud systems. Our Twin Groves, Prairie Creek, and Woolly Hollow systems (Conway and Faulkner Counties) consist of three gas gathering, compression, dehydration and treating facilities. Our Wilson Creek (Van Buren County) and Rose Bud (White County) systems each consist of a gas gathering system and related dehydration and compression facilities. All of our systems gather natural gas produced by customers and deliver customers' gas to unaffiliated pipelines for downstream sale.

Other

We also own and operate systems in the Granite Wash, Avalon Shale/Bone Spring, and the Haynesville/Bossier Shales. Our Indian Creek system, which is located in Roberts County, Texas in the Granite Wash, includes a rich gas gathering system, compression facility and processing plant. Our Las Animas system, which is located in Eddy County, New Mexico, consists of three gas gathering systems located in the Morrow/Atoka reservoir and the Avalon Shale/Bone Spring rich gas trend in the Permian Basin. In mid-July 2014, we substantially completed a Phase 2 expansion of our Willow Lake project which included a 20 MMcf/d cryogenic processing facility and expansion of our gathering system, anchored by a 10-year fixed-fee gas gathering and processing agreement with Trinity River Energy, LLC (formerly "Legend Production Holdings, LLC") (Trinity) in Eddy County, New Mexico at a cost of approximately $19 million. These projects support emerging production from one of the most active drilling areas within the region. Our Sabine system, which is located in Sabine Parish, Louisiana, includes high-pressure gas gathering pipelines that provide gathering and treating services for producers in the Haynesville/Bossier Shale.

PRB Niobrara

Our G&P segment includes our 50% equity interest in the Jackalope system, which we account for under the equity method of accounting. The Jackalope system is a gas gathering system being developed to support a 311,000 gross acre AOD operated by Chesapeake Energy Corporation (Chesapeake) and RKI Exploration and Production LLC (RKI) in the core of the PRB Niobrara Shale. The Jackalope system, which is also 50% owned and operated by Williams Partners LP (Williams), consists of approximately 162 miles of gathering pipelines and 24,080 horsepower of compression equipment located in Converse County, Wyoming. The existing system, which connects to 77 well pads, is supported by a 20-year gathering and processing agreement with Chesapeake and RKI under which Jackalope receives cost-of-service based fees with annual redeterminations sufficient to provide Jackalope a fixed return on all capital invested to build out and expand the system over the life of the contract. In January 2015, the construction of the 120 MMcf/d Bucking Horse processing plant was completed and placed into service. We expect volumes at the Bucking Horse processing plant to significantly increase throughout the first quarter of 2015. In addition, the gathering system continues to expand with the most recent compression facility placed into service in January 2015. We are actively working with area producers to develop additional gathering and processing facilities beyond our Jackalope acreage in the region.

We invested approximately $105 million in Jackalope during the year ended December 31, 2014. Our Jackalope interest, which we acquired in July 2013, was financed in part through a joint venture formed by our consolidated subsidiary, Crestwood Niobrara LLC (Crestwood Niobrara), with General Electric Capital Corporation and GE Structured Finance, Inc. (collectively, GE). Crestwood Niobrara manages the commercial operations of Jackalope. See Item 15, Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Jackalope.

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The table below summarizes certain contract profile information (including our equity investment) as of December 31, 2014:

Shale Play	Type of Services	Type of Contracts[1]	Gross Acreage Dedication	Major Customers	Weighted Average Remaining Contract Terms (in years)
Marcellus	Gathering	Fixed-fee[2]	140,000	Antero	17
	Compression	Fixed-fee	—	Antero	5
Barnett	Gathering	Fixed-fee	140,000	Quicksilver Resources Inc.[3], Devon Energy Corporation	8
	Processing	Fixed-fee	—	Quicksilver Resources Inc.[3], Devon Energy Corporation	8
	Compression	Fixed-fee	—	Quicksilver Resources Inc.[3], Devon Energy Corporation	8
Fayetteville	Gathering	Fixed-fee	143,000	BHP Billiton Petroleum	10
	Treating	Fixed-fee	—	BHP Billiton Petroleum	10
Other[4]	Gathering	Fixed-fee	151,000	Sabine Oil and Gas, Trinity River Energy	10
	Processing	Mixed	—	Sabine Oil and Gas, Trinity River Energy	10
PRB Niobrara[5]	Gathering	Fixed-fee cost-of-service	311,000	Chesapeake	17
	Processing	Fixed-fee cost-of-service	—	Chesapeake	17

(1) Fixed-fee contracts represent contracts in which our customers agree to pay a flat rate based on the amount of gas delivered. Mixed contracts include percent-of-proceeds and fixed-fee arrangements. Our fixed-fee cost-of-service contracts have fees designed to recover operating costs and capital expenditures plus a fixed return.
(2) Antero has provided minimum volume commitments under our agreement, which increase from an average of 425 MMcf/d in 2015 up to an average of 450 MMcf/d in 2016, 2017 and 2018, respectively.
(3) Eni SpA and Toyko Gas own approximately 27.5% and 25%, respectively, of Quicksilver Resources Inc.'s (Quicksilver) Barnett assets.
(4) Other shale plays include Granite Wash, Haynesville / Bossier and Avalon / Bone Spring.
(5) Our PRB Niobrara assets are owned by Jackalope, our 50% equity method investment.

Storage and Transportation

We own and operate high-performance natural gas storage facilities with an aggregate working gas storage capacity of approximately 79.3 Bcf, including our 50.01% ownership interest in Tres Palacios Gas Storage Company LLC (Tres Palacios), which we account for under the equity method of accounting. Our storage facilities have low maintenance costs, long useful lives and comparatively high cycling capabilities.

Storage Facilities. We have four storage facilities located in New York and Pennsylvania. The interconnectivity of our storage facilities with interstate pipelines offers significant flexibility to our customers, and our facilities are located in close proximity to prolific supply sources. Each of our storage facilities are 100% contracted. Our natural gas storage facilities, each of which generates fee-based revenues, include:

- Stagecoach, a FERC-certificated 26.2 Bcf multi-cycle, depleted reservoir storage facility owned and operated by our Central New York Oil And Gas Company, L.L.C. (CNYOG) subsidiary. A 24-mile, 30-inch diameter south pipeline lateral connects the storage facility to Tennessee Gas Pipeline Company, LLC's (TGP) 300 Line, and a 10-mile, 20-inch diameter north pipeline lateral connects to the Millennium Pipeline (Millennium);

- Thomas Corners, a FERC-certificated 7.0 Bcf multi-cycle, depleted reservoir storage facility owned and operated by our Arlington Storage Company, LLC (Arlington Storage) subsidiary. An 8-mile, 12-inch diameter pipeline lateral connects the storage facility to TGP's 200 Line, and a 7.8-mile, 8-inch diameter pipeline lateral connects to Millennium. Thomas Corners is also connected to Dominion Transmission Inc. (Dominion) system through our Steuben facility;

- Steuben, a FERC-certificated 6.2 Bcf single-cycle, depleted reservoir storage facility owned and operated by Arlington Storage. A 15-mile, 12-inch diameter pipeline lateral connects the storage facility to the Dominion system, and a 6-inch diameter pipeline measuring less than one mile connects our Steuben and Thomas Corners storage facilities; and

- Seneca Lake, a FERC-certificated 1.5 Bcf multi-cycle, bedded salt storage facility owned and operated by Arlington Storage. A 19-mile, 16-inch diameter pipeline lateral connects the storage facility to the Millennium and Dominion systems.

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The following provides additional information about our natural gas storage facilities (including our equity investment) as of December 31, 2014:

Storage Facility / Location	Certificated Working Gas Storage Capacity (Bcf)		Certificated Maximum Injection Rate (MMcf/d)	Certificated Maximum Withdrawal Rate (MMcf/d)	Pipeline Connections
Stagecoach Tioga County, NY; Bradford County, PA	26.2		250	500	TGP's 300 Line; Millennium; Transco's Leidy Line[(1)]
Thomas Corners Steuben County, NY	7.0		70	140	TGP's 200 Line; Millennium; Dominion
Seneca Lake Schuyler County, NY	1.5	(2)	73	145	Dominion; Millennium
Steuben Steuben County, NY	6.2		30	60	TGP's 200 Line; Millennium; Dominion
Consolidated Total	40.9		423	845	
Tres Palacios[(3)]	38.4		1,000	2,500	Multiple[(4)]
Total	79.3		1,423	3,345	

(1) Stagecoach is connected to Transcontinental Gas Pipe Line Corporation's (Transco) Leidy Line through our MARC I Pipeline.

(2) We have been authorized by the FERC to expand Seneca Lake’s working gas storage capacity to 2 Bcf.

(3) The Tres Palacios assets are owned by Tres Palacios Holdings LLC (Tres Holdings), our 50.01% equity-method investment.

(4) Tres Palacios is interconnected to Florida Gas Transmission Company, LLC, Kinder Morgan Tejas Pipeline, L.P., Houston Pipe Line Company, Central Texas Gathering System, Natural Gas Pipeline Company of America, Transco, TGP, Valero Natural Gas Pipe Line Company, Channel Pipeline Company, and Texas Eastern Transmission, L.P.

In December 2014, we sold our 100% membership interest in Tres Palacios, which owns a 38.4 Bcf multi-cycle salt dome gas storage facility located in Texas, to Tres Holdings, a joint venture formed by Crestwood Midstream and Brookfield Infrastructure Group (Brookfield) for cash consideration of approximately $132.8 million, of which approximately $66.4 million was paid by Crestwood Midstream. The natural gas storage facility's 60-mile, dual 24-inch diameter header system (including a 51-mile north pipeline lateral and an approximate 11-mile south pipeline lateral) interconnects with 10 pipeline systems and can receive residue gas from the tailgate of Kinder Morgan Inc.'s Houston Central processing plant. The certificated maximum injection rate of the Tres Palacios storage facility is 1,000 MMcf/d and the certificated maximum withdrawal rate is 2,500 MMcf/d. As a result of this transaction, Crestwood Midstream owns 50.01% of Tres Palacios and operates its natural gas storage facility. Brookfield owns the remaining 49.99% interest in Tres Palacios. See Part IV, Item 15, Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our divestiture of Tres Palacios and our investment in unconsolidated affiliates.

Transportation Facilities. We own natural gas transportation facilities located in New York and Pennsylvania. These facilities have low maintenance costs and long useful lives, and they are located in or near the Marcellus Shale.

Throughput on our transportation assets can also be expanded at relatively low capital costs. In 2014, our transportation facilities delivered approximately 1.8 Bcf/d of natural gas on a firm or interruptible basis for our transportation and storage customers. Our natural gas transportation facilities include:

- North-South Facilities, which include compression and appurtenant facilities installed to expand transportation capacity on the Stagecoach north and south pipeline laterals. The bi-directional facilities, which are owned and operated by CNYOG, provide more than 457 MMcf/d of firm interstate transportation capacity to shippers. The North-South Facilities generate fee-based revenues under a negotiated rate structure authorized by the FERC;

- MARC I Pipeline, a 39-mile, 30-inch diameter interstate natural gas pipeline that connects the Stagecoach south lateral and TGP's 300 Line in Bradford County, Pennsylvania, with Transco’s Leidy Line in Lycoming County, Pennsylvania. The bi-directional pipeline, which is owned and operated by CNYOG, provides more than 645 MMcf/d of firm interstate transportation capacity to shippers. It includes a 16,360 horsepower gas-fired compressor station near the Transco interconnection, and a 15,000 horsepower electric-powered compressor station at the interconnection between the Stagecoach south lateral and TGP’s 300 Line. The MARC I Pipeline generates fee-based revenues under a negotiated rate structure authorized by the FERC; and

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- East Pipeline, a 37.5 mile, 12-inch diameter natural gas intrastate pipeline located in New York, which transports 30 MMcf/d of natural gas from Dominion to the Binghamton, New York city gate. The pipeline, which is owned and operated by Crestwood Pipeline East, LLC (CPE), runs within three miles of our Stagecoach north lateral's point of interconnection with Millennium. The East Pipeline generates fee-based revenues under a negotiated rate structure authorized by the New York State Public Service Commission (NYPSC).

The table below summarizes our major contract information associated with our facilities (including our equity investment) as of December 31, 2014:

Facility	Type of Services	Type of Contracts[1]	Contract Volumes	Major Customers	Weighted Average Remaining Contract Terms (in years)
North-South Facilities	Transportation	Firm	457 MMcf/d	Southwestern Energy, Anadarko Energy Services Company (Anadarko), Chesapeake, Cabot Oil, Mitsui & Co., Ltd. (Mitsui)	4
MARC I Pipeline	Transportation	Firm	645 MMcf/d	Chesapeake Energy, Statoil Natural Gas, Anadarko, Mitsui, Sequent Energy Management (Sequent)	6
East Pipeline	Transportation	Firm	30 MMcf/d	NY State Electric & Gas Corp	6
Stagecoach	Storage	Firm	21.4 Bcf	Consolidated Edison of NY, New Jersey Natural Gas, Repsol Energy North America Corporation (Repsol), Sequent	3
Thomas Corners	Storage	Firm	5.7 Bcf	Repsol, Tenaska Gas Storage, LLC, Emera Inc.	2
Seneca Lake	Storage	Firm	1.5 Bcf	Dominion Transmission Inc., NY State Electric & Gas Corp, DTE Energy Trading	3
Steuben	Storage	Firm	6.2 Bcf	PSEG Energy Resources & Trade LLC, Repsol, Pivot Utility Holdings	3
Tres Palacios[2]	Storage	Firm	23.5 Bcf	Brookfield, Anadarko, Repsol, Koch Energy Services LLC, MGI	3

(1)

Firm contracts represent take-or-pay contracts whereby our customers agree to pay for a specified amount of storage or transportation capacity, whether or not the capacity is utilized.

(2) The Tres Palacios assets are owned by Tres Holdings, our 50.01% equity-method investment.

NGL and Crude Services

The operations comprising our NGL and crude segment primarily include our proprietary NGL supply and logistics business, crude oil rail terminals, the Arrow gathering system, our fleet of over-the-road crude oil and produced water transportation assets, NGL storage facilities, and US Salt, LLC (US Salt).

Proprietary NGL Supply and Logistics. Our proprietary NGL supply and logistics business utilizes assets under our ownership or control to effectively provide supply "flow assurance" to producers, refiners and other customers. We are able to offer services that ensure uninterruptible NGL supply flows at attractive economic values by optimizing a portfolio of NGL processing, storage, and transportation assets. These assets consist primarily of:

- our fleet of rail and rolling stock, which also includes our rail-to-truck terminals located in Florida, New Jersey, New York and Rhode Island, and our truck maintenance facilities located in Indiana, Mississippi, New Jersey and Ohio;

- our West Coast NGL operations, which provides processing, fractionation, storage, transportation and marketing services to producers, refiners and other customers. Located near Bakersfield, California, our West Coast facilities include 24 million gallons of aboveground NGL storage capacity, 25 MMcf/d of natural gas processing capacity, 12,000 Bbls/d of NGL fractionation capacity, 8,000 Bbls/d of butane isomerization capacity and NGL rail and truck

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take-away options. We separate NGLs from natural gas, deliver to local natural gas pipelines, and retain NGLs for further processing at our fractionation facility, as well as provide butane isomerization and refrigerated storage services. Our isomerization facility chemically changes normal butane to isobutane, which we provide to Western US refineries for motor fuel production;

- our NGL storage facilities include the Seymour and Bath storage facilities. The Seymour storage facility is located in Seymour, Indiana, and has 21 million gallons of underground NGL storage capacity and 1.2 million gallons of aboveground "bullet" storage capacity. The facility's receipts and deliveries are supported by Enterprise Teppo pipeline, allowing pipeline and truck access. The Bath storage facility (owned by Crestwood Midstream) is located in Bath, New York and has 1.7 million gallons of underground NGL storage capacity and is supported by both rail and truck terminal facilities capable of loading and unloading 23 rail cars per day and approximately 100 truck transports per day; and

- NGL pipeline and storage capacity leased from third parties, including more than 500,000 barrels of NGL working storage capacity at major hubs in Mt. Belvieu, Texas and Conway, Kansas.

COLT Hub. The COLT Hub consists of our integrated crude oil loading and storage terminals and interconnecting pipeline facilities located in the heart of the Bakken and Three Forks Shale oil-producing areas in Williams County, North Dakota. It has 1.1 million barrels of crude oil working storage capacity and is capable of loading up to 160,000 Bbls/d utilizing two 8,700-foot rail loops and three release and depart tracks that can accommodate 120-car unit trains. Customers can source crude oil for rail loading through interconnected gathering systems, a twelve-bay truck unloading rack and the COLT Connector, a 21-mile, 10-inch bi-directional pipeline that connects the COLT terminal to our storage tank at Dry Fork (Beaver Lodge/Ramberg junction). The COLT Hub is connected to the Meadowlark Midstream Company, LLC and Hiland Partners, LP (Hiland) crude oil gathering systems at the COLT terminal, and the Enbridge Energy Partners, L.P., and Tesoro Corporation (Tesoro) pipeline systems at Dry Fork.

Arrow. The Arrow system gathers crude oil, rich natural gas and produced water from wells operating on the Fort Berthold Indian Reservation in the core of the Bakken Shale in McKenzie and Dunn Counties, North Dakota. The system, which is located approximately 60 miles southeast of the COLT Hub, connects to our COLT Hub through the Hiland and Tesoro crude oil pipeline systems. The Arrow system includes approximately 540 miles of gathering lines (including approximately 170 miles of crude oil gathering pipeline, 200 miles of natural gas gathering pipeline, and 170 miles of produced water gathering lines), a 23-acre central delivery point with multiple pipeline take-away outlets and a fully-automated truck loading facility, and salt water disposal wells. Our operations are anchored by long-term, primarily fee-based gathering contracts with blue-chip producers who have dedicated over 150,000 acres to the Arrow system, and our underlying contracts provide for fixed-fee gathering services with annual escalators for crude oil, natural gas and produced water gathering services.

Crude Oil Transportation Fleet. Our over-the-road crude oil transportation fleet consists of approximately 82 tractors, 107 trailer tanks, 22 double bottom body tanks and 17 service vehicles with 48,000 Bbls/d of crude oil and produced water transportation capacity. We acquired most of these assets through our acquisition of substantially all of the operating assets of two trucking companies, LT Enterprises, Inc. and Red Rock Transportation, Inc. in the first half of 2014. We operate our transportation fleet out of Watford City, North Dakota, and we provide hauling services primarily to the oilfields of western North Dakota and eastern Montana.

US Salt. US Salt is an industry-leading solution mining and salt production company located on the shores of Seneca Lake near Watkins Glen in Schuyler County, New York. It is one of five major solution mined salt manufacturers in the United States, capable of producing more than 400,000 tons of evaporated salt products for food, industrial and pharmaceutical uses. The solution mining process used by US Salt creates salt caverns that can be converted into natural gas and NGL storage capacity.

PRBIC. Our NGL and crude services segment also includes our approximate 50% interest in Powder River Basin Industrial Complex, LLC (PRBIC), which we account for under the equity method of accounting. PRBIC owns an early stage crude oil rail terminal located in Douglas County, Wyoming that supports crude oil volumes produced within the PRB Niobrara. The rail loading terminal, which we jointly own with Enserco Midstream LLC, is capable of loading up to 20,000 Bbls/d utilizing two rail loops that can accommodate unit trains. The terminal also has 140,000 barrels of crude oil working storage capacity. See Part IV, Item 15, Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in PRBIC.

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The table below summarizes our major contract information associated with the Arrow system and the COLT Hub as of December 31, 2014:

Facility	Type of Services	Type of Contracts(1)	Gross Acreage Dedication	Volumes(2)	Major Customers	Weighted Average Remaining Contract Terms (in years)
Arrow	Gathering - crude oil, natural gas and water	Fixed-fee	150,000	—	WPX Energy, Whiting Petroleum Corporation, Halcon Resources Corporation, XTO Energy Inc., QEP Resources, Inc. and Enerplus Corporation	5
COLT	Rail Loading	Fixed-fee	—	149,300 Bbl/d	Tesoro, U.S. Oil, BP, Sunoco Inc., Statoil Inc	3

(1) Fixed-fee contracts represent contracts in which our customers agree to pay a flat rate based on the amount of commodity delivered.
(2) There is no contracted volume associated with Arrow's fixed-fee contracts due to the nature of those contracts.

Growth Projects

Gathering and Processing

In January 2015, the Bucking Horse processing plant was completed and placed into service. We anticipate expanding the Jackalope gathering system over the next several years and are actively working with area producers to develop additional gathering and processing facilities beyond our Jackalope acreage in the region. The completion of the Bucking Horse processing plant adds a substantial component to our portfolio of fee-based contracts and provides additional opportunities for long-term infrastructure development as production from emerging PRB Niobrara continues to increase.

Storage and Transportation

North/South Pipeline (NS-1 Expansion). The first phase of our NS-1 Expansion was placed into service in December 2014, and we expect the second phase to be completed in the first quarter of 2015. This expansion provides approximately 200 MMcf/day of incremental delivery capacity into Millennium Pipeline on the north end of the system. We are actively pursuing incremental projects on the North/South Pipeline that would provide additional delivery capability and increased market access, including providing access to new sources of supply from both Susquehanna and Bradford Counties.

MARC I. We have executed a precedent agreement with a shipper to provide for a new supply interconnect with Williams. In conjunction with this new supply interconnect, we will expand our delivery meter into Transco by over 250 MMcf/d. We will conduct an open season for this project in the first quarter of 2015.

MARC II. In October 2014, we conducted a non-binding open season for the MARC II Pipeline, a 30-mile greenfield natural gas pipeline designed to transport Marcellus dry gas to northeastern demand markets. As proposed, the MARC II Pipeline would transport natural gas volumes approximately 30 miles from the southern terminus of our MARC I Pipeline to the proposed PennEast Pipeline, a new interconnect on Transco's Leidy Line, and Transco’s proposed Atlantic Sunrise Expansion Project in Luzerne County, Pennsylvania. We received non-binding expressions of interest for firm transportation service on the MARC II Pipeline in excess of 700 MMcf/d. Subject to FERC authorization, sufficient binding shipper commitments, and certain other factors beyond our control, we anticipate an in-service date for the MARC II Pipeline in the fourth quarter of 2017.

NGL and Crude Services

Arrow. We are continuing to build out the Arrow gathering system to its total design capacity of 125,000 Bbls/d of crude oil gathering, 100 MMcf/d of gas gathering, and 40,000 Bbls/d of produced water gathering. Given that the Arrow system was designed and constructed to handle significantly greater volumes than those flowing today and that our producer customers are responsible for the costs of connecting their wells to our system, we expect to complete the Arrow system build-out to reach targeted operational throughput capacities with modest organic capital requirements by the end of 2015. We are also constructing a 200,000 barrel crude oil storage tank at the Arrow central delivery point, which we expect to complete and place into service by the third quarter of 2015. The new storage tank, which is expected to cost approximately $16 million, is commercially supported by a take-or-pay storage agreement for 50% of the tank's working storage capacity.

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COLT Hub. In 2014, we expanded our COLT Hub to increase our crude oil throughput and storage capacities. The expansion primarily included the installation of additional crude oil loading arms and pumps at our rail loading rack; the construction of parallel rail tracks on which we will be able to store additional unit trains; the construction of two floating-roof crude oil storage tanks; the construction of additional truck unloading racks; and, modifications that enable us to receive more crude oil from interconnected gathering systems. The expansion increased our unit train loading capacity to 160,000 Bbls/d, our truck unloading capacity to 96,000 Bbls/d, our working storage capacity to 1.1 million barrels, and our input capacity from third-party gathering systems to approximately 105,000 Bbls/d. We have entered into customer contracts that supported a substantial portion of our capital investment.

NGL Storage Project. We are developing an NGL storage facility in Schuyler County, New York. We have requested from the New York State Department of Environmental Conservation (NYSDEC) the permits necessary to store up to 2.1 million barrels of propane and butane in underground caverns created by US Salt’s solution-mining process. Following an issues conference scheduled in mid-February 2015, an Administrative Law Judge will determine whether any significant issues remain open that must be addressed in an adjudicatory hearing. We continue to believe the NYDEC will issue the permit required for us to construct, own and operate the proposed storage facility. We have recorded approximately $38 million of costs in property, plant and equipment and $66 million of goodwill related to this NGL storage facility as of December 31, 2014. We estimate that the remaining capital required to complete the proposed storage project is approximately $20 million.

Customers

For the year ended December 31, 2014, Tesoro accounted for approximately 12% of our total consolidated revenues. No customer accounted for 10% or more of our total consolidated revenues for the year ended December 31, 2013. For the year ended December 31, 2012, Quicksilver and Antero accounted for approximately 47% and 11% of our total consolidated revenues.

Industry Background

The midstream sector of the energy industry provides the link between exploration and production and the delivery of crude oil, natural gas and their components to end-use markets. The midstream sector consists generally of gathering, processing, storage, and transportation activities. We gather crude oil and natural gas; process natural gas; fractionate NGLs; store crude oil, NGLs and natural gas; and transport crude oil, NGLs and natural gas.

The diagram below depicts the main segments of the midstream sector value chain:

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Crude Oil

Pipelines typically provide the most cost-effective option for shipping crude oil. Crude oil gathering systems normally comprise a network of small-diameter pipelines connected directly to the well head that transport crude oil to central receipt points or interconnecting pipelines through larger diameter trunk lines. Common carrier pipelines frequently transport crude oil from central delivery points to logistics hubs or refineries under tariffs regulated by the FERC or state authorities. Logistic hubs provide storage and connections to other pipeline systems and modes of transportation, such as railroads and trucks. Pipelines not engaged in the interstate transportation of crude may also be proprietary or leased entirely to a single customer.

Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. Trucking is generally limited to low volume, short haul movements because trucking costs escalate sharply with distance, making trucking the most expensive mode of crude oil transportation. Railroads provide additional transportation capabilities for shipping crude oil between gathering storage systems, pipelines, terminals and storage centers and end-users.

Natural Gas

Midstream companies within the natural gas industry create value at various stages along the value chain by gathering natural gas from producers at the wellhead, processing and separating the hydrocarbons from impurities and into lean gas (primarily methane) and NGLs, and then routing the separated lean gas and NGL streams for delivery to end-markets or to the next stage of the value chain.

A significant portion of natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This rich natural gas is generally not acceptable for transportation in the nation's transmission pipeline system or for residential or commercial use. Processing plants extract the NGLs, leaving residual lean gas that meets transmission pipeline quality specifications for ultimate consumption. Processing plants also produce marketable NGLs, which, on an energy equivalent basis, typically have a greater economic value as a raw material for petrochemicals and motor gasolines than as a component of the natural gas stream.

Gathering. At the earliest stage of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads or pad sites in the production area. Gathering systems transport gas from the wellhead to downstream pipelines or a central location for treating and processing. Gathering systems are often designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow for additional production and well connections without significant incremental capital expenditures. A byproduct of the gathering process is the recovery of condensate liquids, which are sold on the open market.

Compression. Gathering systems are operated at pressures intended to enable the maximum amount of production to be gathered from connected wells. Through a mechanical process known as compression, volumes of natural gas at a given pressure are compressed to a sufficiently higher pressure, thereby allowing those volumes to be delivered into a higher pressure downstream pipeline to be shipped to market. Because wells produce at progressively lower field pressures as they age, it becomes necessary to add additional compression over time to maintain throughput across the gathering system.

Treating and Dehydration. Treating and dehydration involves the removal of impurities such as water, carbon dioxide, nitrogen and hydrogen sulfide that may be present when natural gas is produced at the wellhead. Impurities must be removed for the natural gas to meet the quality specifications for pipeline transportation, and end users normally cannot consume (and will not purchase) natural gas with a high level of impurities. Therefore, to meet downstream pipeline and end user natural gas quality standards, the natural gas is dehydrated to remove water and is chemically treated to separate the impurities from the natural gas stream.

Processing. Once impurities are removed, pipeline-quality residue gas is separated from NGLs. Most rich natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods: cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation of processing, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

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Natural gas is processed not only to remove heavier hydrocarbon components that would interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGLs than as natural gas. The principal component of residue gas is methane, although some lesser amount of entrained ethane typically remains. In some cases, processors have the option to leave ethane in the gas stream or to recover ethane from the gas stream, depending on ethane's value relative to natural gas. The processor's ability to "reject" ethane varies depending on the downstream pipeline's quality specifications. The residue gas is sold to industrial, commercial and residential customers and electric utilities.

Fractionation. Once NGLs have been removed from the natural gas stream, they can be broken down into their base components to be useful to commercial customers. Mixed NGL streams can be further separated into purity NGL products, including ethane, propane, normal butane, isobutane, and natural gasoline. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream, and essentially occurs in stages consisting of the boiling off of hydrocarbons one by one. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. In general, fractionators are used in the following order: (i) deethanizer, which separates ethane from the NGL stream, (ii) depropanizer, which separates propane, (iii) debutanizer, which boils off the butanes and leaves the pentanes and heavier hydrocarbons in the NGL stream, and (iv) butane splitter (or deisobutanizer), which separates isobutanes and normal butanes.

Transportation and Storage. Once raw natural gas has been treated or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. The natural gas pipeline grid in the United States transports natural gas from producing regions to customers, such as LDCs, industrial users and electric generation facilities.

Historically, the concentration of natural gas production in a few regions of the United States generally required transportation pipelines to transport gas not only within a state but also across state borders to meet national demand. However, a recent shift in supply sources, from conventional to unconventional, has affected the supply patterns, the flows and the rates that can be charged on pipeline systems. The impacts vary among pipelines according to the location and the number of competitors attached to these new supply sources. These changing market dynamics are prompting midstream companies to evaluate the construction of short-haul pipelines as a means of providing demand markets with cost-effective access to newly-developed production regions, as compared to relying on higher-cost, long-haul pipelines that were originally designed to transport natural gas greater distances across the country.

Natural gas storage plays a vital role in maintaining the reliability of gas available for deliveries. Natural gas is typically stored in underground storage facilities, including salt dome caverns, bedded salt caverns and depleted reservoirs. Storage facilities are most often utilized by pipeline companies to manage temporary imbalances in operations; natural gas end-users, such as LDCs, to manage the seasonality and variability of demand and to satisfy future natural gas needs; and, independent natural gas marketing and trading companies in connection with the execution of their trading strategies.

Salt Manufacturing

According to the United States Geological Survey, approximately 280 million metric tons of salt were produced in the world in 2012. Salt is generally categorized into four types based upon the method of production: evaporated salt, solar salt, rock salt and salt in brine. Dry salt is produced through the following methods: solution mining and mechanical evaporation, solar evaporation or deep-shaft mining. US Salt produces salt using solution mining and mechanical evaporation. In solution mining, wells are drilled into salt beds or domes and then water is injected into the formation and circulated to dissolve the salt. After salt is removed from a solution-mined salt deposit, the empty cavern can be used to store other substances, such as natural gas, NGLs or compressed air.

The salt solution, or brine, is next pumped out of the cavern and taken to a processing plant for evaporation. The brine may be treated to remove minerals and then pumped into vacuum pans in which the brine is boiled, and evaporated until a salt slurry is created. The slurry is then dried and separated. Depending on the type of salt product to be produced, iodine and an anti-caking agent may be added to the salt. Most food grade table salt is produced in this manner.

Competition

Our G&P operations compete for customers based on reputation, operating reliability and flexibility, price, creditworthiness, and service offerings, including interconnectivity to producer-desired takeaway options (e.g., processing facilities and pipelines). We face strong competition in acquiring new supplies in the production basins in which we operate, and competition customarily is impacted by the level of drilling activity in a particular geographic region and fluctuations in commodity prices. Our primary competitors include other midstream companies with G&P operations and producer-owned systems, and certain competitors enjoy first-mover advantages over us and may offer producers greater gathering and processing efficiencies, lower operating costs and more flexible commercial terms.

Our proprietary NGL supply and logistics business competes primarily with integrated major oil companies, refiners and processors, and other energy companies that own or control transportation and storage assets that can be optimized for supply, marketing and logistics services.

Natural gas storage and pipeline operators compete for customers primarily based on geographic location, which determines connectivity and proximity to supply sources and end-users, as well as price, operating reliability and flexibility, available capacity and service offerings. Our primary competitors in our natural gas storage market include other independent storage providers and major natural gas pipelines with storage capabilities embedded within their transmission systems. Our primary competitors in our natural gas transportation market include major natural gas pipelines and intrastate pipelines that can transport natural gas volumes between interstate systems. Long-haul pipelines often enjoy cost advantages over new pipeline projects with respect to options for delivering greater volumes to existing demand centers, and new projects and expansions proposed from time to time may serve the markets we serve and effectively displace the service we provide to customers.

Our crude oil rail terminals primarily compete with crude oil pipelines and other midstream companies that own and operate rail terminals in the markets we serve. The crude oil logistics business is characterized by strong competition for supplies, and competition is based largely on customer service quality, pricing, and geographic proximity to customers and other market hubs.

Our salt operations compete for customers primarily based on price and service. Because transportation costs are a material component of the costs borne by our customers, most of our customers are geographically located east of the Mississippi River.

Regulation

Our operations are subject to extensive regulation by federal, state and local authorities. The regulatory burden on our operations increases our cost of doing business and, in turn, impacts our profitability. In general, midstream companies have experienced increased regulatory oversight over the past few years, and we expect this trend to continue for the foreseeable future.

Pipeline Safety

We are subject to pipeline safety regulations imposed by the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline facilities. Currently, all of our natural gas pipelines used in gathering, storage and transportation activities are subject to regulation by PHMSA under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), and all of our NGL and crude oil pipelines used in gathering, storage and transportation activities are subject to regulation by PHMSA as hazardous liquids pipelines under the Hazardous Liquid Pipeline Safety Act of 1979, as amended (HLPSA).

These federal statutes and PHMSA implementing regulations collectively impose numerous safety requirements on pipeline operators, such as the development of a written qualification program for individuals performing covered tasks on pipeline facilities and the implementation of pipeline integrity management programs. For example, pursuant to the authority under the NGPSA and HLPSA, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect high-consequence areas, such as areas of high population and areas unusually sensitive to environmental damage. Integrity management programs require more frequent inspections and other preventative measures to ensure pipeline safety in high consequence areas.

We plan to continue testing under our pipeline integrity management programs to assess and maintain the integrity of our pipelines in accordance with PHMSA regulations. Notwithstanding our preventive and investigatory maintenance efforts, we may incur significant expenses if anomalous pipeline conditions are discovered or due to the implementation of more stringent pipeline safety standards resulting from new or amended legislation. For example, President Obama in January 2012 signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

Furthermore, PHMSA is considering changes to its natural gas transmission pipeline regulations to, among other things, expand the scope of high consequence areas, strengthen integrity management requirements applicable to existing operators; strengthen or expand non-integrity pipeline management standards relating to such matters as valve spacing, automatic or remotely-controlled valves, corrosion protection, and gathering lines; and add new regulations to govern the safety of underground natural gas storage facilities, including underground storage caverns and injection or withdrawal well piping that are not regulated today. We cannot predict the final outcome of these legislative or regulatory efforts or the precise impact that compliance with any resulting new safety requirements may have on our business.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most are certified by the Department of Transportation to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate pipelines, states vary considerably in their authority and capacity to address pipeline safety. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements, and we do not anticipate any significant difficulty in complying with applicable state laws and regulations.

Natural Gas Storage and Transportation

Our interstate natural gas storage and transportation operations are subject to regulation by the FERC under the Natural Gas Act, and two of our subsidiaries (CNYOG and Arlington Storage) are regulated by the FERC as natural gas companies. Under the Natural Gas Act, the FERC has authority to regulate gas transportation services in interstate commerce, which includes natural gas storage services. The FERC exercises jurisdiction over rates charged for services and the terms and conditions of service; the certification and construction of new facilities; the extension or abandonment of services and facilities; the maintenance of accounts and records; the acquisition and disposition of facilities; standards of conduct between affiliated entities; and various other matters. Regulated natural gas companies are prohibited from charging rates determined by the FERC to be unjust, unreasonable, or unduly discriminatory, and both the existing tariff rates and the proposed rates of regulated natural gas companies are subject to challenge.

The rates and terms and conditions of our natural gas storage and transportation services are found in the FERC-approved tariffs of (i) CNYOG, the owner of the Stagecoach facility, the North-South Facilities and the MARC I Pipeline, and (ii) Arlington Storage, the owner of the Thomas Corners, Seneca Lake and Steuben facilities. CNYOG and Arlington Storage are authorized to charge and collect market-based rates for storage services, and CNYOG is authorized to charge and collect negotiated rates for transportation services. Market-based and negotiated rate authority allows us to negotiate rates with individual customers based on market demand, which we then make public. A loss of market-based or negotiated rate authority or any successful complaint or protest against the rates charged or provided by CNYOG or Arlington Storage could have an adverse impact on our revenues.

In addition, the Energy Policy Act of 2005 amended the Natural Gas Act to (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, and FERC rules, regulations or orders thereunder. As a result of the Energy Policy Act of 2005, the FERC has the authority to impose civil penalties for violations of these statutes and FERC rules, regulations and orders, up to $1 million per day per violation.

Our interstate natural gas storage operations are also subject to non-rate regulation by various state agencies. For example, the NYSDEC has jurisdiction over well drilling, conversion and plugging in New York. The NYDEC therefore regulates aspects of our Stagecoach, Thomas Corners, Seneca Lake and Steuben natural gas storage facilities.

Our intrastate pipeline in New York (the East Pipeline) is subject to lightened regulation under NYPSC regulations and policies. Lightened regulation generally exempts us from NYPSC regulation applicable to the provision of retail service. CPE, as the owner and operator of the East Pipeline, remains subject to limited corporate (e.g., obtaining approval prior to any transfer of its ownership interests or the issuance of debt securities) and operational and safety (e.g., filing of vegetation management plan) regulation established and maintained by the NYPSC.

Natural Gas Gathering

Natural gas gathering facilities are exempt from FERC jurisdiction under Section 1(b) of the Natural Gas Act. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, we believe that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the Natural Gas Act and the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the Natural Gas Act or the Natural Gas Policy Act. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the Natural Gas Act or the Natural Gas Policy Act, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our natural gas gathering operations may be subject to ratable take and common purchaser statutes in the states in which we operate. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply, and they generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

The states in which we operate gathering systems have adopted a form of complaint-based regulation of natural gas gathering operations, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. To date, these regulations have not had an adverse effect on our systems. We cannot predict whether such a complaint will be filed against us in the future, and failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies.

In Texas, we have filed with the Texas Railroad Commission (TRRC) to establish rates and terms of service for certain of our pipelines. Our assets in Texas include intrastate common carrier NGL pipelines subject to the regulation of the TRCC, which requires that our NGL pipelines file tariff publications that contain all the rules and regulations governing the rates and charges for services we perform. NGL pipeline rates may be limited to provide no more than a fair return on the aggregate value of the pipeline property used to render services.

NGL Storage

Our NGL storage terminals are subject primarily to state and local regulation. For example, the Indiana Department of Natural Resources (INDNR) and the NYSDEC have jurisdiction over the underground storage of NGLs and well drilling, conversion and plugging in Indiana and New York, respectively. Thus, the INDNR regulates aspects of our

Seymour facility, and the NYSDEC regulates aspects of the Bath facility.

We filed an application with the NYSDEC in October 2009 for an underground storage permit for our Watkins Glen NGL storage development project. The agency issued a Positive Declaration for the project in November 2010, determined in August 2011 that the Draft Supplemental Environmental Impact Statement we submitted for the project was complete, and held public hearings on the project in September and November 2011. In early 2012, based on concerns expressed by interested stakeholders and conversations with NYSDEC Staff, we informed the agency that we would reduce our environmental footprint and modified our brine pond design. In September 2012, we submitted to the NYSDEC final drawings and plans for our revised project design. In August 2014, the NYDEC announced that it would convene an issues conference to determine if there are any significant issues that require an adjudicatory hearing. The issues conference was held in mid-February 2015. We continue to pursue the state regulatory permits required to construct our proposed Finger Lakes NGL storage facility near Watkins Glen, New York but we cannot predict with certainty if and when the permitting process will be concluded.

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Crude Oil Transportation

The transportation of crude oil by common carrier pipelines on an interstate basis is subject to regulation by the FERC under the Interstate Commerce Act (ICA), the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. FERC regulations require interstate common carrier petroleum pipelines to file with the FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. The ICA and FERC regulations also require that such rates be just and reasonable, and to be applied in a non-discriminatory manner and to not confer undue preference upon any shipper. The transportation of crude oil by common carrier pipelines on an intrastate is subject to regulation by state regulatory commissions. The basis for intrastate crude oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. Intrastate common carriers must also offer service to all shippers requesting service on the same terms and under the same rates. Our crude oil pipelines in North Dakota are not common carrier pipelines and, therefore, are not subject to rate regulation by the FERC or any state regulatory commission.

Certain of our crude oil operations located in North Dakota are subject to state regulation by the North Dakota Industrial Commission (NDIC). For example, gas conditioning requirements established by the NDIC recently will require operators of crude by rail terminals to report to the NDIC any crude volumes received for loading that exceed federal vapor pressure limits. State legislation has been proposed that, if passed, would authorize and require the NDIC to promulgate regulations under which produced water pipelines would be required to, among other things, install leak detection facilities and post bonds to cover potential remediation costs associated with releases. Moreover, the regulation of our customers' production activities by the NDIC impacts our operations. For example, on July 1, 2014, the NDIC issued an order pursuant to which the agency adopted legally enforceable “gas capture percentage goals” targeting the capture of certain percentages of natural gas produced in the state by specified dates. Exploration and production operators in the state may be required to install new equipment to satisfy these goals, and any failure by operators subject to the legal requirements to meet these gas capture percentage goals would subject those operators to production restrictions, which developments could reduce the amount of commodities we gather on the Arrow system from those operators who are our customers and have a corresponding adverse impact on our business and results of operations.

Portions of our Arrow gathering system, which is located on the Fort Berthold Indian Reservation, are subject to regulation by the Mandan, Hidatsa & Arikara Nation (MHA Nation). An entirely separate and distinct set of laws and regulations applies to operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and Bureau of Land Management (BLM), and the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, environmental standards, Tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are often subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

We are therefore subject to various laws and regulations pertaining to Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas operations within Native American reservations. One or more of these Native American requirements, or delays in obtaining necessary approvals or permits necessary to operate on tribal lands pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

PHMSA is currently reviewing the adequacy of Bakken crude laboratory testing measures used to determine the packaging group selection for shipment of crude by rail. PHMSA's objective is to confirm that crude being offered for shipment by rail has been properly classified and characterized to ensure the safe transport to end users. We, as the owner of a Bakken crude loading terminal, are providing input as this review process progresses through multiple agencies and organizations.

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Supply and Logistics

The transportation of crude oil and NGLs by truck is subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations, which are administered by the DOT, cover the transportation of hazardous materials.

IRS Audit

On January 29, 2014, the Internal Revenue Service (IRS) issued a Notice of Beginning of Administrative Proceeding (NBAP) to us stating that the IRS is commencing an examination of our 2011 partnership tax return. A copy of the NBAP is available on our website at www.crestwoodlp.com. This is a routine compliance examination of various items of partnership income, gain, deductions, losses and credits. The examination is in progress, and it is currently not known whether the IRS will propose any adjustments to the 2011 tax return, whether such adjustments would be material, or how such adjustments would affect unitholders.

We are cooperating with the IRS examiners auditing this return. Unitholders should consult their tax advisers if they have any questions.

Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, regional, state and local laws and regulations governing the discharge and emission of pollutants into the environment, environmental protection, or occupational health and safety. These laws and regulations may impose significant obligations on our operations, including the need to obtain permits to conduct regulated activities; restrict the types, quantities and concentration of materials that can be released into the environment; apply workplace health and safety standards for the benefit of employees; require remedial activities or corrective actions to mitigate pollution from former or current operations; and impose substantial liabilities on us for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the activities in a particular area.

The following is a summary of the more significant existing federal environmental laws and regulations, each as amended from time to time, to which our business operations are subject:

- The Comprehensive Environmental Response, Compensation and Liability Act, a remedial statute that imposes strict liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- The Resource Conservation and Recovery Act, which governs the treatment, storage and disposal of solid wastes, including hazardous wastes;
- The Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring and reporting requirements;
- The Water Pollution Control Act, also known as the federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters;
- The Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of substances into below-ground formations that may adversely affect drinking water sources;
- The National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and

comment;

- The Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas; and
- The Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

Certain of these environmental laws impose strict, joint and several liability for costs required to clean up and restore properties where pollutants have been released regardless of whom may have caused the harm or whether the activity was performed in compliance with all applicable laws. In the course of our operations, generated materials or wastes may have been spilled or released from properties owned or leased by us or on or under other locations where these materials or wastes have been taken for recycling or disposal. In addition, many of the properties owned or leased by us were previously operated by third parties whose management, disposal or release of materials and wastes was not under our control. Accordingly, we may be liable for the costs of cleaning up or remediating contamination arising out of our operations or as a result of activities by others who previously occupied or operated on properties now owned or leased by us. Private parties, including the owners of properties that we lease and facilities where our materials or wastes are taken for recycling or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. We may not be able to recover some or any of these additional costs from insurance.

In 2014, we experienced three releases on our Arrow produced water gathering system. Approximately 28,000 barrels of produced water were released on lands within the boundaries of the Fort Berthold Indian Reservation. We have substantially completed our remediation efforts. In October 2014, we received certain data requests from the EPA related to the releases. We responded to the EPA's request for information on January 30, 2015. We have also notified our insurance carriers of the releases under our environmental policies and we believe our remediation costs will be recoverable under our insurance policies.

Future developments, such as stricter environmental laws or regulations, or more stringent enforcement of existing requirements could directly affect our operations. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45 percent from 2012 levels by 2025, and, in December 2014, the EPA published a proposed rulemaking that it expects to finalized by October 1, 2015 that would seek to reduce the National Ambient Air Quality Standard for ozone to between 65 and 70 parts per billion for both the 8-hour primary and secondary standards. In matters that could have an indirect adverse effect on our business by decreasing demand for the services that we offer, the EPA and other federal and state agencies are conducting studies of potential adverse impacts that certain drilling methods (including hydraulic fracturing) may have on water quality and public health, whereas, Congress has considered, and several states have proposed or enacted, legislation or regulations imposing more stringent or costly requirements for exploration and production companies to develop and produce hydrocarbons.

Employees

As of January 30, 2015, we had 1,374 full-time employees, 298 of which were general and administrative employees and 1,076 of which were operational. As of January 30, 2015, US Salt had 130 employees, 96 of which are members of a labor union. We believe that our relationship with our employees (including union labor) is satisfactory.

Available Information

Our website is located at www.crestwoodlp.com. We make available, free of charge, on or through our website our annual reports on Form 10-K, which include our audited financial statements, 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 Exchange Act as soon as we electronically file such material with the SEC. These documents are also available, free of charge, at the SEC's website at www.sec.gov. In addition, copies of these documents, excluding exhibits, may be requested at no cost by contacting Investor Relations, Crestwood Equity Partners LP, 700 Louisiana Street, Suite 2550, Houston, Texas 77002, and our telephone number is (832) 519-2200.

We also make available within the “Corporate Governance” section of our website our corporate governance guidelines, the charter of our Audit Committee and our Code of Business Conduct and Ethics. Requests for copies may be directed in writing to Crestwood Equity Partners LP, 700 Louisiana Street, Suite 2550, Houston, Texas 77002, Attention: General Counsel. Interested parties may contact the chairperson of any of our Board committees, our Board's independent directors as a group or our full Board in writing by mail to Crestwood Equity Partners LP, 700 Louisiana Street, Suite 2550, Houston, Texas 77002, Attention: General Counsel. All such communications will be delivered to the director or directors to whom they are addressed.

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Item 1A. Risk Factors

Risks Inherent in Our Business

Our business depends on hydrocarbon supply and demand fundamentals, which can be adversely affected by numerous factors outside of our control.

Our success depends on the supply and demand for natural gas, NGLs and crude oil. The degree to which our business is impacted by changes in supply or demand varies. Our business can be negatively impacted by sustained downturns in supply and demand for one or more commodities, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. For example, major factors that will impact natural gas demand domestically will be the realization of potential liquefied natural gas exports and demand growth within the power generation market, and a major factor impacting oil and gas supplies has been the significant growth in unconventional sources such as shale plays. In addition, the supply and demand for natural gas, NGLs and crude oil for our business will depend on many other factors outside of our control, some of which include:

- adverse changes in general global economic conditions. The level and speed of the recovery from the recent recession remains uncertain and could impact the supply and demand for natural gas and our future rate of growth in our business;
- adverse changes in domestic regulations that could impact the supply or demand for oil and gas;
- technological advancements that may drive further increases in production and reduction in costs of developing shale plays;
- competition from imported supplies and alternate fuels;
- commodity price changes that could negatively impact the supply of, or the demand for these products;
- increased costs to explore for, develop, produce, gather, process or transport commodities;
- adoption of various energy efficiency and conservation measures; and
- perceptions of customers on the availability and price volatility of our services, particularly customers' perceptions on the volatility of commodity prices over the longer-term.

If volatility and seasonality in the oil and gas industry decrease, because of increased production capacity or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline. In addition to volatility and seasonality, an extended period of high commodity prices would likely place upward pressure on the costs of associated expansion activities. An extended period of low commodity prices could adversely impact storage and transportation values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business, financial condition, and results of operations.

Our future growth may be limited if we do not complete growth projects or make acquisitions.

Our business strategy depends on our ability to complete growth projects and make acquisitions that increase cash generated from operations on a per unit basis. We may be unable to complete successful, accretive growth projects or acquisitions for any of the following reasons, among others:

- we fail to identify (or we are outbid for) attractive expansion or development projects or acquisition candidates that satisfy our economic and other criteria;
- we cannot raise financing for such projects or acquisitions on economically acceptable terms;
- we fail to secure adequate customer commitments to use the facilities to be developed, expanded or acquired; or
- we cannot obtain governmental approvals or other rights, licenses or consents needed to complete such projects or acquisitions on time or on budget, if at all.

The development and construction of gathering, processing, storage and transportation facilities involves numerous regulatory, environmental, safety, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. When we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular growth project. For instance, if we build a new gathering system or transmission pipeline, the construction may occur over an extended period of time and we will not receive material increases in revenues until the project is placed in service. Accordingly, if we do pursue growth projects, we can provide no assurances that our efforts will provide a platform for additional growth for our company.

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The growth projects and acquisitions we complete may not perform as anticipated.

Even if we complete acquisitions or growth projects that we believe will be strategic and accretive, such acquisitions and projects may nevertheless reduce our cash available for distribution due to the following factors, among others:

- mistaken assumptions about capacity, revenues, synergies, costs (including operating and administrative, capital, debt and equity costs), customer demand, growth potential, assumed liabilities and other factors;
- the failure to receive cash flows from a growth project or newly acquired asset due to delays in the commencement of operations for any reason;
- unforeseen operational issues or the realization of liabilities that were not known to us at the time the acquisition or growth project was completed;
- the inability to attract new customers or retain acquired customers to the extent assumed in connection with an acquisition or growth project;
- the failure to successfully integrate growth projects or acquired assets or businesses into our operations and/or the loss of key employees; or
- the impact of regulatory, environmental, political and legal uncertainties that are beyond our control.

In particular, we may construct facilities to capture anticipated future growth in production and/or demand in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our business, financial condition, results of operations and ability to make distributions.

If we complete future growth projects or acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources. If any growth projects or acquisitions we ultimately complete are not accretive to our cash available for distribution, our ability to make distributions may be reduced.

We may rely upon third-party assets to operate our facilities, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such third-party assets.

Certain of our operations depend on assets owned and controlled by third parties to operate effectively. For example, (i) certain of our “rich gas” gathering systems depend on interconnections and processing plants owned by third parties for us to move gas off our systems; (ii) our crude oil rail terminals depend on railroad companies to move our customers’ crude oil to market; and (iii) our natural gas storage facilities rely on third-party interconnections and pipelines to receive and deliver natural gas. Since we do not own or operate these third-party facilities, their continuing operation is outside of our control. If third-party facilities become unavailable or constrained, or other downstream facilities utilized to move our customers’ product to their end destination become unavailable, it could have a material adverse effect on our business, financial condition, results of operations, and ability to make distributions.

In addition, the rates charged by processing plants, pipelines and other facilities interconnected to our assets affect the utilization and value of our services. Significant changes in the rates charged by these third parties, or the rates charged by the third parties that own “downstream” assets required to move commodities to their final destinations, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We depend on a limited number of customers for a substantial portion of our revenues.

We generate a substantial portion of our gathering revenue from a limited number of oil and gas producers. Within our G&P segment, the top two producers (Antero in the Marcellus Shale and Quicksilver in the Barnett Shale) accounted for approximately 3% and 2% of our total consolidated revenues in 2014, respectively. Within our NGL and crude services segment, five producers primarily on our Arrow system in the Bakken Shale accounted for approximately 34% of our total consolidated revenues in 2014. Given the current commodity price environment and its anticipated impact on shale production, we expect our gathering earnings to remain leveraged to a limited number of producers in 2015 as we continue to build out our gathering systems, particularly in the Marcellus, Bakken and PRB Niobrara. Because we depend on a limited number of customers, a loss of a significant customer or failure to perform by a significant customer could cause a significant decline in our revenues. In particular, in February 2015, Quicksilver announced its decision not to make an interest payment due under its indenture and to enter into a 30-day grace period under the applicable indenture. This could result in an event of default under the indenture, which could lead Quicksilver to seek voluntary protection under Chapter 11 of the United States Bankruptcy Code.

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Although we have obtained acreage dedications from many producer customers, most of our gathering contracts do not contain minimum volume requirements that would protect us against volumetric risks associated with lower-than-forecast volumes flowing through our systems. Our producer customers do not have contractual obligations to develop their properties in the areas covered by our acreage dedications, and they may determine that it is more attractive to direct their capital spending and resources to other areas. A decrease in producer capital spending and reserves in the areas covered by our acreage dedications with our significant gathering customers could result in reduced volumes serviced by us and a material decline in our revenue and cash flow.

Declines in natural gas, NGL or crude prices could adversely affect our business.

Sustained low natural gas, NGL or crude oil prices impact natural gas and oil exploration and production activity levels and can result in a decline in the production of hydrocarbons over time, resulting in reduced throughput on our systems and terminals. Such a decline could also potentially affect the ability of our customers to continue their operations. As a result, sustained low natural gas and crude oil prices could have a material adverse effect on our business, results of operations, and financial condition. In general, the prices of natural gas, oil, condensate, NGLs and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. For example, market prices for natural gas has declined substantially since 2008 and have remained low for several years. More recently, the increased supply resulting from the rapid development of shale plays throughout North America has contributed significantly to the rapid decline in crude oil prices.

Our gathering and processing operations depend, in part, on drilling and production decisions of others.

Our gathering and processing operations are dependent on the continued availability of natural gas and crude oil production. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems, or the rate at which production from a well declines. Our gathering systems are connected to wells whose production will naturally decline over time, which means that our cash flows associated with these wells will decline over time. To maintain or increase throughput levels on our gathering systems and utilization rates at our natural gas processing plants, we must continually obtain new natural gas and crude oil supplies. Our ability to obtain additional sources of natural gas and crude oil primarily depends on the level of successful drilling activity near our systems, our ability to compete for volumes from successful new wells, and our ability to expand our system capacity as needed. If we are not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering and processing facilities would decline, which could have a material adverse affect on our results of operations and distributable cash flow.

Although we have acreage dedications from customers that include certain producing and non-producing oil and gas properties, our customers are not contractually required to develop the reserves and or properties they have dedicated to us. We have no control over producers or their drilling and production decisions in our areas of operations, which are affected by, among other things, (i) the availability and cost of capital; (ii) prevailing and projected commodity prices; (iii) demand for natural gas, NGLs and crude oil, (iv) levels of reserves and geological considerations, (v) governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and (vi) the availability of drilling rigs and other development services. Fluctuations in energy prices can also greatly affect the development of oil and gas reserves. Drilling and production activity generally decreases as commodity prices decrease, and sustained declines in commodity prices could lead to a material decrease in such activity. Because of these factors, even if oil and gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Reductions in exploration or production activity in our areas of operations could lead to reduced utilization of our systems.

Estimates of oil and gas reserves depend on many assumptions that may turn out to be inaccurate, and future volumes on our gathering systems may be less than anticipated.

We normally do not obtain independent evaluations of natural gas or crude oil reserves connected to our gathering systems. We therefore do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. It often takes producers longer periods of time to determine how to efficiently develop and produce hydrocarbons from unconventional shale plays than conventional basins, which can result in lower volumes becoming available as soon as expected in the shale plays in which we operate. If the total reserves or estimated life of the reserves connected to our gathering systems is less than anticipated and we are unable to secure additional sources of natural gas or crude oil, it could have a material adverse effect on our business, results of operations and financial condition.

Our NGL supply and logistics businesses are seasonal and generally have lower cash flows in certain periods during the year, which may require us to borrow money to fund our working capital needs of these businesses.

The natural gas liquids inventory we pre-sell to our customers is higher during the second and third quarters of a given year, and our cash receipts during that period are lower. As a result, we may have to borrow money to fund the working capital needs of our NGL supply and logistics businesses during those periods. Any restrictions on our ability to borrow money could impact our ability to pay quarterly distributions to our unitholders.

Counterparties to our commodity derivative and physical purchase and sale contracts in our NGL supply and logistics businesses may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

We encounter risk of counterparty non-performance in our NGL supply and logistics businesses. Disruptions in the price or supply of NGLs for an extended or near term period of time could result in counterparty defaults on our derivative and physical purchase and sale contracts. This could impair our expected earnings from the derivative or physical sales contracts, our ability to obtain supply to fulfill our sales delivery commitments or our ability to obtain supply at reasonable prices, which could result adversely affect our financial condition and results of operations.

Our NGL supply and logistics businesses are subject to commodity risk, basis risk, or risk of adverse market conditions which can adversely affect our financial condition and results of operations.

We attempt to lock in a margin for a portion of the commodities we purchase by selling such commodities for physical delivery to our customers or by entering into future delivery obligations under contracts for forward sale. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, and sales or future delivery obligations. Any event that disrupts our anticipated physical supply of commodities could expose us to risk of loss resulting from the need to fulfill our obligations required under contracts for forward sale. 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. Transportation costs and timing differentials are components of basis risk. In a backwardated market (when prices for future deliveries are lower than current prices), basis risk is created with respect to timing. In these instances, physical inventory generally loses value as the price of such physical inventory declines over time. Basis risk cannot be entirely eliminated, and basis exposure, particularly in backwardated or other adverse market conditions, can adversely affect our financial condition and results of operations.

We have limited experience in the crude oil gathering business.

We acquired the Arrow gathering system in November 2013, which serves customers producing crude oil and rich gas from the Bakken Shale formation. The Arrow system is the first crude oil and produced water gathering system that we have been required to build out and operate. Other operators of gathering systems in the Bakken have more experience in the construction, operation and maintenance of crude oil gathering systems than we do. Our lack of experience may hinder our ability to fully implement our business plan in a timely and cost-effective manner, which may adversely affect our results of operations and ability to make distributions.

Our industry is highly competitive, and increased competitive pressure could adversely affect our ability to execute our growth strategy.

We compete with other energy midstream enterprises, some of which are much larger and have significantly greater financial resources or operating experience, in our areas of operation. Our competitors may expand or construct infrastructure that creates additional competition for the services we provide to customers. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make distributions.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund operations, limit our ability to react to changes in our business or industry, and place us at a competitive disadvantage.

We had approximately $2.4 billion of long-term debt outstanding as of December 31, 2014. Our inability to generate sufficient cash flow to satisfy debt obligations or to obtain alternative financing could materially and adversely affect our business, results of operations, financial condition and business prospects.

Our substantial debt could have important consequences to our unitholders. For example, it could:

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- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future capital expenditures and working capital, to engage in development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive covenants or terms of our debt;
- result in an event of default if we fail to satisfy debt obligations or fail to comply with the financial and other restrictive covenants contained in the agreements governing our indebtedness, which event of default could result in all of our debt becoming immediately due and payable and could permit our lenders to foreclose on any of the collateral securing such debt;
- require a substantial portion of cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use cash flow to fund operations, capital expenditures and future business opportunities;
- increase our cost of borrowing;
- restrict us from making strategic acquisitions or causing us to make non-strategic divestitures;
- limit our flexibility in planning for, or reacting to, changes in our business or industry in which we operate, placing us at a competitive disadvantage compared to our peers who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploring; and
- impair our ability to obtain additional financing in the future.

Realization of any of these factors could adversely affect our financial condition, results of operations and cash flows.

Restrictions in our revolving credit facilities could adversely affect our business, financial condition, results of operations and ability to make distributions.

We have a $495 million revolving credit facility that matures in July 2016. Our revolving credit facility will be available to fund working capital and our growth projects, make acquisitions and for general partnership purposes. Crestwood Midstream has a $1 billion revolving credit facility (expandable up to $1.25 billion) that matures in October 2018. Crestwood Midstream's revolving credit facility will be available to fund working capital and its growth projects, make acquisitions and for general partnership purposes.

Our revolving credit facilities contain various covenants and restrictive provisions that will limit our ability to, among other things:

- incur additional debt;
- make distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company; and
- transfer or otherwise dispose of assets.

Furthermore, our revolving credit facilities contain covenants requiring us to maintain certain financial ratios. For example, (i) our revolving credit facility requires maintenance of a consolidated leverage ratio (as defined in our credit agreement) of no greater than 5.50 to 1.0 for the quarter ended December 31, 2014, 5.25 to 1.0 for the quarter ended March 31, 2015, 5.00 to 1.0 for the quarter ended June 30, 2015, and 4.75 to 1.0 for the quarter ended September 30, 2015 and all subsequent quarters; (ii) our interest coverage ratio (as defined in our credit agreement) should not be less than 2.50 to 1.00, and (ii) Crestwood Midstream's credit facility requires maintenance of a consolidated leverage ratio (as defined in its credit agreement) of not more than 5.00 to 1.00 (and, if applicable, 5.50 to 1.0 during certain periods immediately following a material acquisition) and an interest coverage ratio (as defined in its credit agreement) of not less than 2.50 to 1.00.

Borrowings under our revolving credit facility are secured by pledges of the equity interests of, and guarantees by, substantially all of our restricted domestic subsidiaries, and liens on substantially all of our real and personal property. Borrowings under

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Crestwood Midstream's revolving credit facility are secured by pledges of the equity interests of, and guarantees by, substantially all of its restricted domestic subsidiaries, and liens on substantially all of its real property (outside of New York) and personal property.

The provisions of our credit agreements may affect our ability to obtain future financing 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 revolving credit facilities could result in events of default, which could enable our lenders, subject to the terms and conditions of credit agreements, to declare any outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If the payment of any such debt is accelerated, our assets (and, with respect to Crestwood Midstream's revolver, Crestwood Midstream's assets) may be insufficient to repay such debt in full, and the holders of our common units could experience a partial or total loss of their investment.

A change of control could result in us facing substantial repayment obligations under our revolving credit facilities.

Our credit agreements contain provisions relating to change of control of our general partners and our partnerships. If these provisions are triggered, our outstanding bank indebtedness may become due. In such an event, there is no assurance that we would be able to pay the indebtedness, in which case the lenders under our revolving credit facilities would have the right to foreclose on our assets, which would have a material adverse effect on us. There is no restriction on the ability of our general partner or its parent companies to enter into a transaction which would trigger the change of control provisions, and there are no restrictions on our ability to enter into a transaction which would trigger Crestwood Midstream's change of control provisions.

Our ability to make cash distributions may be diminished, and our financial leverage could increase, if we are not able to obtain needed capital or financing on satisfactory terms.

Historically, each of the Crestwood Equity and Crestwood Midstream have used cash flow from operations, borrowings under its respective revolving credit facility and issuances of debt or equity to fund their respective capital programs, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our respective operations to fund growth. If our cash flow from operations decreases as a result of lower throughput volumes on our systems or otherwise, our ability to expend the capital necessary to expand our business or increase our future cash distributions may be limited. If our cash flow from operations is insufficient to satisfy our financing needs, we cannot be certain that additional financing will be available to us on acceptable terms, if at all. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition or general economic conditions at the time of any such financing or offering. Even if we are successful in obtaining the necessary funds, the terms of such financings could have a material adverse effect on our business, results of operation, financial condition and ability to make cash distributions to our unitholders. Further, incurring additional debt may significantly increase our interest expense and financial leverage and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the cash distribution rate which could materially decrease our ability to pay distributions. If additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Increases in interest rates could adversely impact our unit price, ability to issue equity or incur debt for acquisitions or other purposes, and ability to make payments on our debt obligations.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Therefore, changes in interest rates either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make payments on our debt obligations.

The loss of key personnel could adversely affect our ability to operate.

Our success is dependent upon the efforts of our senior management team, as well as on our ability to attract and retain both executives and employees for our field operations. Our senior executives have significant experience in the oil and gas industry and have developed strong relationships with a broad range of industry participants. The loss of any of these executives, or the loss of key field employees operating in competitive markets like the Bakken Shale and the Marcellus Shale, could prevent us from implementing our business strategy and could have a material adverse effect on our customer relationships, results of operations and ability to make distributions.

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We operate in the PRB Niobrara and the Texas Gulf Coast through joint ventures that may limit our operational flexibility.

Our operations in the PRB Niobrara and our storage operations in the Texas Gulf Coast market are conducted through joint venture arrangements (including the Jackalope and PRBIC joint ventures in the PRB Niobrara and our Tres Palacios joint venture in the Texas Gulf Coast market), and we may enter additional joint ventures in the future. In a joint venture arrangement, we could have less operational flexibility, as actions must be taken in accordance with the applicable governing provisions of the joint venture. In certain cases, we:

- could have limited ability to influence or control certain day to day activities affecting the operations;
- could have limited control on the amount of capital expenditures that we are required to fund with respect to these operations;
- could be dependent on third parties to fund their required share of capital expenditures;
- may be subject to restrictions or limitations on our ability to sell or transfer our interests in the jointly owned assets; and
- may be forced to offer rights of participation to other joint venture participants in certain areas of mutual interest.

In addition, our joint venture participants may have obligations that are important to the success of the joint venture, such as the obligation to pay substantial carried costs pertaining to the joint venture and to pay their share of capital and other costs of the joint venture. The performance and ability of the third parties to satisfy their obligations under joint venture arrangements is outside of our control. If these parties do not satisfy their obligations, our business may be adversely affected. Our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives, and disputes between us and our joint venture partners may result in delays, litigation or operational impasses. The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to conduct business that is the subject of a joint venture, which could in turn negatively affect our financial condition and results of operations.

We may not be able to renew or replace expiring contracts.

Our primary exposure to market risk occurs at the time our existing contracts expire and are subject to renegotiation and renewal. As of December 31, 2014, the weighted average remaining term of (i) our consolidated portfolio of natural gas storage and transportation contracts is approximately three years, (ii) our consolidated portfolio of natural gas gathering contracts is approximately 11 years, and (iii) our consolidated portfolio of crude oil gathering contracts is approximately five years. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the macroeconomic factors affecting natural gas, NGL and crude economics for our current and potential customers;
- the level of existing and new competition to provide services to our markets;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

Any failure to extend or replace a significant portion of our existing contracts, or extending or replacing them at unfavorable or lower rates, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

The fees we charge to customers under our contracts may not escalate sufficiently to cover our cost increases, and those contracts may be suspended in some circumstances.

Our costs may increase at a rate greater than the rate that the fees we charge to third parties increase pursuant to our contracts with them. In addition, some third parties' obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of natural gas or crude oil is curtailed or cut off. Force majeure events generally include, without limitation, revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions, mechanical or physical failures of our equipment or facilities or those of third parties. If our escalation of fees is insufficient to cover increased costs or if any third party suspends or terminates its contracts with us, our business, financial condition, results of operations and ability to make distributions could be materially adversely affected.

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Our operations are subject to extensive regulation, and regulatory measures adopted by regulatory authorities could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to extensive regulation by federal, state and local regulatory authorities. For example, because we transport natural gas in interstate commerce and we store natural gas that is transported in interstate commerce, our natural gas storage and transportation facilities are subject to comprehensive regulation by the FERC under the Natural Gas Act. Federal regulation under the Natural Gas Act extends to such matters as:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;
- the types of services we may offer to our customers;
- the certification and construction of new, or the expansion of existing, facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- contracts for service between storage and transportation providers and their customers;
- creditworthiness and credit support requirements;
- the maintenance of accounts and records;
- relationships among affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services; and
- various other matters.

Natural gas companies may not charge rates that, upon review by FERC, are found to be unjust and unreasonable or unduly discriminatory. Existing interstate transportation and storage rates may be challenged by complaint and are subject to prospective change by FERC. Additionally, rate increases proposed by a regulated pipeline or storage provider may be challenged and such increases may ultimately be rejected by FERC. We currently hold authority from FERC to charge and collect (i) market-based rates for interstate storage services provided at the Stagecoach, Thomas Corners, Seneca Lake, Steuben and Tres Palacios facilities and (ii) negotiated rates for interstate transportation services provided by our North-South Facilities and MARC I Pipeline. FERC's “market-based rate” policy allows regulated entities to charge rates different from, and in some cases, less than, those which would be permitted under traditional cost-of-service regulation. Among the sorts of changes in circumstances that could raise market power concerns would be an expansion of capacity, acquisitions or other changes in market dynamics. There can be no guarantee that we will be allowed to continue to operate under such rate structures for the remainder of those assets' operating lives. Any successful challenge against rates charged for our storage and transportation services, or our loss of market-based rate authority or negotiated rate authority, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. Our market-based rate authority for our natural gas storage facilities may be subject to review and possible revocation if FERC determines that we have the ability to exercise market power in our market area. If we were to lose our ability to charge market-based rates, we would be required to file rates based on our cost of providing service, including a reasonable rate of return. Cost-of-service rates may be lower than our current market-based rates.

There can be no assurance that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation and storage facilities. Failure to comply with applicable regulations under the Natural Gas Act, the Natural Gas Policy Act of 1978, the Pipeline Safety Act of 1968 and certain other laws, and with implementing regulations associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties of up to $1,000,000 per day, per violation.

A change in the jurisdictional characterization of our gathering assets may result in increased regulation, which could cause our revenues to decline and operating expenses to increase.

Our natural gas and crude oil gathering operations are generally exempt from the jurisdiction and regulation of the FERC, except for certain anti-market manipulation provisions. FERC regulation nonetheless affects our businesses and the markets for products derived from our gathering businesses. The FERC's policies and practices across the range of its oil and gas regulatory activities, including, for example, its policies on open access transportation, rate making, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we have no assurance that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has regularly been the subject of substantial, on-going litigation. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by the FERC, the courts or Congress. If our gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of certain gathering agreements.

State and municipal regulations also impact our business. Common purchaser statutes generally require gatherers to gather or provide services without undue discrimination as to source of supply or producer; as a result, these statutes restrict our right to decide whose production we gather or transport. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we currently operate have adopted complaint-based regulation of gathering activities, which allows oil and gas producers and shippers to file complaints with state regulators in an effort to resolve access and rate grievances. Other state and municipal regulations may not directly regulate our gathering business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the rates, terms and conditions of its gathering lines.

Our operations are subject to compliance with environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

Our operations are subject to stringent federal, regional, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. Such environmental laws and regulations impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to comply with applicable legal requirements, the application of specific health and safety criteria addressing worker protections and the imposition of restrictions on the generation, handling, treatment, storage, disposal and transportation of materials and wastes. Failure to comply with such environmental laws and regulations can result in the assessment of substantial administrative, civil and criminal penalties, the imposition of remedial liabilities and the issuance of injunctions restricting or prohibiting some or all of our activities. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where materials or wastes have been disposed or otherwise released. In the course of our operations, generated materials or wastes may have been spilled or released from properties owned or leased by us or on or under other locations where these materials or wastes have been taken for recycling or disposal.

It is also possible that adoption of stricter environmental laws and regulations or more stringent interpretation of existing environmental laws and regulations in the future could result in additional costs or liabilities to us as well as the industry in general or otherwise adversely affect demand for our services and salt products. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45 percent from 2012 levels by 2025, and, in December 2014, the EPA published a proposed rulemaking that it expects to finalized by October 1, 2015 that would seek to reduce the National Ambient Air Quality Standard for ozone to between 65 and 70 parts per billion for both the 8-hour primary and secondary standards.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating and capital costs and reduced demand for our services.

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) 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. Based on these findings, the EPA adopted regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration (PSD) construction and Title V operating permit reviews for greenhouse gases from certain large stationary sources that are already potential major sources of principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet best available control technology standards that typically will be established by the states. The EPA has also adopted regulations requiring the annual reporting of GHG emissions from specified large GHG emission sources in the United States including certain oil and natural gas production, processing, transmission, storage and distribution facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include GHG emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal.

While the United States Congress has considered adopting legislation from time to time to reduce emissions of GHGs, in the absence of any such legislation in recent years, a number of state and regional efforts have emerged that are aimed at tracking or reducing emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, to acquire and surrender emission allowances.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that is produced, which may decrease demand for our midstream services. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

We may incur higher costs as a result of pipeline integrity management program testing and additional safety legislation.

Pursuant to authority under the NGPSA and HLPSA, PHMSA requires pipeline operators to develop integrity management programs for pipelines located where a leak or rupture could harm “high consequence areas”. The regulations require operators like us to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

We estimate that the total future costs to complete the testing required by existing PHMSA regulations will not have a material impact to our results. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program itself.

Moreover, the 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve us, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain instrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The PHMSA has also published an advanced notice of proposed rule making to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office, the agency acknowledged PHMSA's continued assessment of these pipeline safety risks and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. Such legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

Our business involves many hazards and risks, some of which may not be fully covered by insurance.

Our operations are subject to many risks inherent in gathering, processing, storage and transportation segments of the energy midstream industry, such as:

- damage to pipelines and plants, related equipment and surrounding properties caused by natural disasters and acts of terrorism;
- subsidence of the geological structures where we store natural gas or NGLs, or storage cavern collapses;
- operator error;
- inadvertent damage from construction, farm and utility equipment;
- leaks, migrations or losses of natural gas, NGLs or crude oil;
- fires and explosions;
- cyber intrusions; and
- other hazards that could also result in personal injury, including loss of life, property and natural resources damage, pollution of the environmental or suspension of operations.

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These risks could result in substantial losses due to breaches of contractual commitments, personal injury and/or loss of life, damage to and destruction of property and equipment and pollution or other environmental damage. For example, we experienced three releases on our Arrow water gathering system during 2014 that resulted in a spill of an estimated 28,000 barrels of produced water on the Fort Berthold Indian Reservation in North Dakota, the remediation and repair costs of which we believe are covered by insurance but nonetheless potentially subjects us to substantial penalties, fines and damages from regulatory agencies and individual landowners. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. For example, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are also not insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could result in a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities. Although we maintain insurance policies with insurers in such amounts and with such coverages and deductibles as we believe are reasonable and prudent, our insurance may not be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities (particularly our G&P facilities) have been constructed, which subjects us to the possibility of more onerous terms or increased costs to obtain and maintain valid easements and rights-of-way. We obtain standard easement rights to construct and operate its pipelines on land owned by third parties, and our rights frequently revert back to the landowner after we stop using the easement for its specified purpose.

Therefore, these easements exist for varying periods of time. Our loss of easement rights could have a material adverse effect on our ability to operate our business, thereby resulting in a material reduction in our revenue, earnings and ability to make distributions.

Terrorist attacks or “cyber security” events, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other assets might be specific targets of terrorist organizations or “cyber security” events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets, our operations could be disrupted and/or customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation or litigation and or inaccurate information reported from our operations. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

Risks Inherent in an Investment in Us

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses to enable us to pay quarterly distributions to our common unitholders.

We may not have sufficient cash each quarter to pay quarterly distributions to our common unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations and payments of fees and expenses. Before we pay any distributions on our common units, we will establish reserves and pay fees and expenses, including reimbursements to our general partner and its affiliates, for all expenses they incur and payments they make on our behalf. These costs will reduce the amount of cash available to pay distributions to our common unitholders.

The amount of cash we can distribute on our common units will fluctuate from quarter to quarter based on, among other things:

- the amount of cash distributions we receive in connection with our ownership of 100% of Crestwood Midstream’s IDRs and 4% of its common units;

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- the rates we charge for storage and transportation services and the amount of services our customers purchase from us, which will be affected by, among other things, the overall balance between the supply of and demand for commodities, governmental regulation of our rates and services, and our ability to obtain permits for growth projects;
- force majeure events that damage our or third-party pipelines, facilities, related equipment and surrounding properties;
- prevailing economic and market conditions;
- governmental regulation, including changes in governmental regulation in our industry;
- changes in tax laws;
- the level of competition from other midstream companies;
- the level of our operating and maintenance and general administrative costs;
- the level of capital expenditures we make;
- our ability to make borrowings under our revolving credit facility; and
- the cost of acquisitions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including: the level and timing of capital expenditures we make; the cost of acquisitions; our debt service requirements and other liabilities; fluctuations in our working capital needs; our ability to borrow funds and access capital markets; restrictions contained in our debt agreements; and the amount of cash reserves established by our general partner.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our common 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 all of our available cash, 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 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 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 available cash that we have to distribute to our common unitholders.

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

Our partnership agreement does not limit the number of additional limited partner interests we may issue at any time without the approval of our existing common unitholders. The issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- our existing common unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of the common units may decline.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our common unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by Crestwood Holdings, as a result of it owning our general partner, and not by our common unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our common unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

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Common unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the Delaware Act), we may not make a distribution to our common unitholders 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. A purchaser of units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

It may be determined that the right, or the exercise of the right by the limited partners as a group, to (i) remove or replace our general partner, (ii) approve some amendments to our partnership agreement or (iii) take other action under our partnership agreement constitutes “participation in the control” of our business. A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner.

The amount of cash we have available for distribution to common unitholders 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.

The amount of cash we have available for distribution depends primarily upon our cash flow (the majority of which consists of the cash distributions we receive in connection with our ownership of 100% of Crestwood Midstream’s IDRs), including cash flow from reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may pay cash distributions during periods when we record net losses for financial accounting purposes and may not pay cash distributions during periods when we record net income.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Crestwood Holdings and its affiliates may sell common 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 December 31, 2014, Crestwood Holdings and its affiliates beneficially held an aggregate of 53,809,398 limited partner units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market on which the common units are traded.

Risks Inherent in Our Structure and Relationship with Crestwood Midstream

Our primary cash-generating assets are our partnership interests, including incentive distribution rights, in Crestwood Midstream, and our cash flow is therefore materially dependent upon the ability of Crestwood Midstream to make distributions in respect to those partnership interests to its partners.

The amount of cash that Crestwood Midstream can distribute to its unitholders each quarter, including us with respect to our IDRs, principally depends upon the amount of cash Crestwood Midstream generates from its operations, which amounts of cash may fluctuate from quarter to quarter based on, among other things:

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- the rates Crestwood Midstream charges for services and the amount of services their customers purchase from Crestwood Midstream, which will be affected by, among other things, the overall balance between the supply of and demand for natural gas, NGL and crude oil, governmental regulation of Crestwood Midstream's rates and services, and Crestwood Midstream's ability to obtain permits for growth projects;
- force majeure events that damage Crestwood Midstream's or third-party pipelines, facilities, related equipment and surrounding properties;
- prevailing economic and market conditions;
- governmental regulation, including changes in governmental regulation in Crestwood Midstream's industry;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- difficulties in Crestwood Midstream collecting receivables because of its customers' credit or financial problems;
- changes in tax laws;
- the level of competition from other midstream energy companies;
- the level of Crestwood Midstream's operating and maintenance and general administrative costs;
- the level of capital expenditures Crestwood Midstream makes;
- the ability of Crestwood Midstream to make borrowings under its revolving credit facility; and
- the cost of acquisitions.

In addition, the actual amount of cash Crestwood Midstream will have available for distribution will depend on other factors, some of which are beyond its control, including: the level and timing of capital expenditures it makes; the cost of acquisitions; its debt service requirements and other liabilities; fluctuations in its working capital needs; its ability to borrow funds and access capital markets; restrictions contained in its debt agreements and its partnership agreement; and the amount of cash reserves established by its general partner.

We do not have control over many of these factors, including the level of cash reserves established by the board of directors of Crestwood Midstream's general partner. Accordingly, we cannot guarantee that Crestwood Midstream will have sufficient available cash to pay a specific level of cash distributions to its partners.

If Crestwood Midstream reduced its per unit distribution, we would have less cash available for distribution and would probably be required to reduce our per unit distribution. Furthermore, the amount of cash that Crestwood Midstream has available for distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, Crestwood Midstream may be able to make cash distributions during periods when it records losses and may not be able to make cash distributions during periods when it records net income.

To the extent we purchase additional securities from Crestwood Midstream, our rate of growth may be reduced.

Our business strategy may include supporting the growth of Crestwood Midstream by purchasing its securities or lending funds to Crestwood Midstream to provide funding for acquisitions or internal growth projects. To the extent we purchase common units, the rate of our distribution growth may be reduced, at least in the short term, as less of our cash distributions will come from our ownership of Crestwood Midstream's IDRs, which distributions increase at a faster rate than those of our other securities.

We could have an indemnification obligation to Crestwood Midstream, which could materially adversely affect our financial condition.

We have entered into an omnibus agreement with Crestwood Midstream and its general partner that governs certain aspects of our relationship with them. Pursuant to the omnibus agreement, we are generally obligated to indemnify Crestwood Midstream and its affiliates against certain liabilities of the assets of the operations of Crestwood Midstream prior to December 21, 2011. See "Certain Relationships and Related Party Transactions-Omnibus Agreement." Our indemnification obligations under the omnibus agreement could result in substantial expenses and liabilities to us, which could materially adversely affect our financial condition.

Unitholders have less ability to elect or remove management than holders of common stock in a corporation.

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, and do not have the right to elect, our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Crestwood Holdings LLC, the general partner of the sole member of our general partner, Crestwood Holdings LP (Holdings LP), which currently is the only voting member of the general partner of Holdings

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LP, and effectively has the authority to appoint all of our directors. Although our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders, the directors of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to its sole member, Holdings LP.

If unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner generally may not be removed except upon the vote of the holders of 66 % of the outstanding units voting together as a single class.

Our unitholders' voting rights are further restricted by a provision in our partnership agreement 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 and its affiliates, cannot be voted on any matter.

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 our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner, Holdings LP, from transferring its ownership interest in our general partner to a third party. Additionally, Holdings LP's general partner interest in our general partner is pledged as collateral under a Credit Agreement between Crestwood Holdings LLC and various lenders (Holdings Credit Agreement). In the event of a default by Crestwood Holdings LLC under the Holdings Credit Agreement, the lenders may foreclose on the pledged general partner interest and take or transfer control of our general partner without unitholder consent. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by our board of directors and officers. This effectively permits a "change of control" without the vote or consent of the common unitholders.

Cost reimbursements paid to our general partner may be substantial and may reduce our ability to pay the quarterly distribution.

Before making any distributions on our units, we will reimburse our general partner for all expenses it has incurred on our behalf. In addition, our general partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by our general partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions our unitholders. Our general partner has sole discretion to determine the amount of these expenses and fees.

We may issue additional common units without unitholder approval, which would dilute our unitholders' existing ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional common units or other equity securities of equal rank will have the following effects:

- the proportionate ownership interest of our existing unitholders in us will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the relative voting strength of each previously outstanding common unit will be diminished; and
- the market price of the common units or partnership securities may decline.

Crestwood Midstream may issue additional common units, which may increase the risk that it will not have sufficient available cash to maintain or increase its per unit distribution level.

The Crestwood Midstream partnership agreement allows it to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Crestwood Midstream will have the following effects:

- Our unitholders' current proportionate ownership interest in Crestwood Midstream will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of Crestwood Midstream's common units may decline.

The payment of distributions on any additional units issued by Crestwood Midstream may increase the risk that Crestwood Midstream may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

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If we cease to manage and control Crestwood Midstream in the future, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control Crestwood Midstream and are deemed to be an investment company under the Investment Company Act of 1940 (the Investment Company Act) we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Securities and Exchange Commission or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. For further discussion of the importance of our treatment as a partnership for federal income tax purposes and the implications that would result from our treatment as a corporation in any taxable year, please read the risk factor below entitled “The tax treatment of publicly traded partnerships is subject to potential legislative, judicial or administrative changes. If we or Crestwood Midstream were treated as a corporation for federal income tax purposes, or if we or Crestwood Midstream were to become subject to a material amount of state or local taxation, then our cash available for distribution to our unitholders would be substantially reduced.

Although we control Crestwood Midstream through our ownership of its general partner, Crestwood Midstream’s general partner owes fiduciary duties to Crestwood Midstream’s unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and Crestwood Midstream and its limited partners, on the other hand. The directors and officers of Crestwood Midstream’s general partner have fiduciary duties to manage Crestwood Midstream in a manner beneficial to us. At the same time, Crestwood Midstream’s general partner has fiduciary duties to manage Crestwood Midstream in a manner beneficial to Crestwood Midstream and its limited partners. The board of directors of Crestwood Midstream’s general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with Crestwood Midstream may arise in the following situations:

- the allocation of shared overhead expenses to Crestwood Midstream and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Crestwood Midstream, on the other hand;
- the determination of the amount of cash to be distributed to Crestwood Midstream’s limited partners and the amount of cash to be reserved for the future conduct of Crestwood Midstream’s business; and
- the determination whether to make borrowings under Crestwood Midstream’s revolving credit facility to pay distributions to Crestwood Midstream’s limited partners.

The fiduciary duties of our general partner’s officers and directors may conflict with those of Crestwood Midstream’s general partner.

Conflicts of interest may arise because of the relationships among Crestwood Midstream, its general partner and us. Our general partner’s directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our unitholders. Some of our general partner’s directors and officers are also directors and officers of Crestwood Midstream’s general partner, and have fiduciary duties to manage the business of Crestwood Midstream in a manner beneficial to Crestwood Midstream and its unitholders. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

Affiliates of our general partner are not prohibited from competing with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Except as provided in our partnership agreement, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

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

Conflicts of interest may arise among our general partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following:

- Our general partner is allowed to take into account the interests of parties other than us, including Crestwood Midstream and its affiliates and any general partner and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- Our general partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.
- Our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- Our general partner determines which costs it and its affiliates have incurred are reimbursable by us.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- Our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our general partner's fiduciary duties to us and restricts the remedies available for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- provides that our general partner is entitled to make decisions in "good faith" if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

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

If at any time our general partner and its affiliates own more than 80% of our outstanding 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 units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2014, the directors and executive officers of our general partner owned approximately 12% of our common units.

Our cash distribution policy limits our ability to grow.

Because we distribute all of our available cash, our growth may not be as rapid as businesses that reinvest their available cash to expand ongoing operations. If we issue additional units or incur debt to fund acquisitions and growth capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that we will be unable to maintain or increase our per unit distribution level.

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Tax Risks to Common Unitholders

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 federal income tax purposes or we or Crestwood Midstream were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders 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. The value of our investment in Crestwood Midstream depends largely on Crestwood Midstream being treated as a partnership for federal income tax purposes. Despite the fact that we and Crestwood Midstream are each organized as a limited partnership under Delaware law, we and Crestwood Midstream would each be treated as a corporation for U.S. federal income tax purposes unless we each satisfy a "qualifying income" requirement. Based upon our current operations, we and Crestwood Midstream each believe we satisfy the qualifying income requirement.

Failing to meet the qualifying income requirement or a change in current law could cause us or Crestwood Midstream to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. If we or Crestwood Midstream were treated as a corporation for U.S. federal income tax purposes, we each would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, as well as any applicable state or local taxes. Distributions to our unitholders and Crestwood Midstream's unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us or Crestwood Midstream as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our respective common unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement, as well as that of Crestwood Midstream, 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 federal, state or local 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. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders or Crestwood Midstream's unitholders.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us and Crestwood Midstream, or an investment in our or Crestwood Midstream's common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 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 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 and Crestwood Midstream rely for our treatment as a partnership for U.S. federal income tax purposes.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us or Crestwood Midstream 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 or Crestwood Midstream's common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.
Neither we nor Crestwood Midstream has requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS 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 the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which

they trade. In addition, the costs of any contest with the IRS will be borne indirectly by you and our general partner because the costs will reduce our cash available for distribution.

You will be required to pay taxes on your share of our income even if you do not receive cash distributions from us.

You will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability which results from that income.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between your amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our total net taxable income result in a reduction in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation deductions. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities, regulated investment companies 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, including employee benefit plans and individual retirement accounts (known as “IRAs”), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file U. S. federal income tax returns and pay tax on their 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.

We and Crestwood Midstream will treat each purchaser of our respective common units as having the same tax benefits without regard to the specific common units purchased. The IRS may challenge this treatment, which could adversely affect the value of Crestwood Midstream’s and our common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we and Crestwood Midstream will adopt 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 you. It also could affect the timing of these tax benefits or the amount of gain from the sale of Crestwood Midstream’s common units and our common units and could have a negative impact on the value of our respective common units or result in audit adjustments to your 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 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 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 use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly-traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

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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 as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may 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 as having disposed of the loaned units. In that case, he 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 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 loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

We will be considered to have constructively terminated as a partnership for federal income tax purposes if there is a sale or exchange within a twelve-month period of 50% or more of the total interests in our capital and profits. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders which could result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one calendar year. Our termination could also 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 its taxable income for the year of termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for 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. Pursuant to an IRS relief procedure a publicly traded partnership that has technically terminated may request special relief which, if granted by the IRS, among other things, would permit the partnership to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes, estate, inheritance or intangible taxes and foreign taxes that are imposed by the various jurisdictions in which we do business or own property and in which they do not reside. We own property and conduct business in various parts of the United States. Unitholders may be required to file state and local income tax returns in many or all of the jurisdictions in which we do business or own property. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders' responsibility to file all required U. S. federal, state, local and foreign tax returns.

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Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is included in Item 1. Business, and is incorporated herein by reference. We also lease office space for our corporate offices in Houston, Texas and our executive offices in Kansas City, Missouri and Fort Worth, Texas.

We lease and rely upon our customers' property rights to conduct a substantial part of our operations, and we own or lease the property rights necessary to conduct our storage and transportation operations. We believe that we have satisfactory title to our assets. Title to property may be subject to encumbrances. For example, we have granted to the lenders of our revolving credit facility security interests in substantially all of our real property interests. We believe that none of these encumbrances will materially detract from the value of our properties or from our interest in these properties, nor will they materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings.

A description of our legal proceedings is included in Part IV, Item 15, Exhibits, Financial Statement Schedules, Note 15, and is incorporated herein by reference.

Seymour Investigation. We own a propane storage and distribution facility in Seymour, Indiana. On May 15, 2014, the EPA issued a request relating to our compliance with the chemical accident prevention provision at the facility. We responded to the request on August 6, 2014, and at EPA’s request, we submitted additional documentation of compliance on January 30, 2015. Although we have not received a compliance order or settlement agreement from the EPA, we anticipate that the EPA will assess a civil penalty against us and the amount could exceed $100,000.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

Our common units representing limited partner interests are traded on the NYSE under the symbol “CEQP.” The following table sets forth the range of high and low sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per common unit for the periods indicated.

Quarters Ended:	Low	High	Cash Distribution Per Unit
2014			
December 31, 2014	$5.84	$10.73	$0.1375
September 30, 2014	10.55	15.40	0.1375
June 30, 2014	12.85	15.04	0.1375
March 31, 2014	12.41	14.51	0.1375
2013			
December 31, 2013	$11.83	$15.30	$0.1375
September 30, 2013	12.59	16.89	0.135
June 30, 2013	13.55	25.34	0.130
March 31, 2013	18.42	20.91	0.290

The last reported sale price of our common units on the NYSE on February 13, 2015, was $7.09. As of that date, we had 187,349,776 common units issued and outstanding, which were held by 247 unitholders of record.

Cash Distribution Policy

We make quarterly distributions to our partners within approximately 45 days after the end of each fiscal quarter in an aggregate amount equal to our available cash for such quarter. Available cash generally means, with respect to each fiscal quarter, all cash on hand at the end of the quarter less the amount of cash that the general partner determines in its reasonable discretion is necessary or appropriate to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to unitholders for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of the quarter. Working capital borrowings are generally borrowings that are made under our working capital facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

On February 13, 2015, we paid a distribution of $0.1375 per limited partner unit $0.55 per limited partner unit on an annualized basis) to all unitholders of record on February 6, 2015.

Issuer Purchases of Equity Securities

For the year ended December 31, 2014, 159,435 common units were relinquished to us to cover payroll taxes upon the vesting of restricted units.

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Equity Compensation Plan Information

The following table sets forth in tabular format, a summary of equity compensation plan information as of December 31, 2014:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	$—	—
Equity compensation plans not approved by security holders	—	$—	13,812,979
Total	—	$—	13,812,979

Item 6. Selected Financial Data.

These consolidated financial statements were originally the financial statements of Legacy Crestwood GP prior to being acquired by us on June 19, 2013. Our acquisition of Legacy Crestwood GP was accounted for as a reverse acquisition under the purchase method of accounting in accordance with the accounting standards for business combinations. The accounting for a reverse acquisition results in the legal acquiree (Legacy Crestwood GP) being the acquirer for accounting purposes. Although Legacy Crestwood GP was the acquirer for accounting purposes, we were the acquirer for legal purposes; consequently, we changed our name from Crestwood Gas Services GP, LLC to Crestwood Equity Partners LP.

The income statement and cash flow data for each of the three years ended December 31, 2014 and balance sheet data as of December 31, 2014 and 2013 were derived from our audited financial statements. We derived the income statement and cash flow data for each of the two years ended December 31, 2011 and the balance sheet data as of December 31, 2012, 2011 and 2010 from our accounting records. The selected financial data is not necessarily indicative of results to be expected in future periods and should be read together with Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations and Part IV, Item 15, Exhibits and Financial Statement Schedules included elsewhere in this report.

The following table summarizes our results for the years ended December 31, 2014, 2013, 2012 and 2011 and two periods in 2010: January 1, 2010 through September 30, 2010 (the Predecessor Period) and October 1, 2010 through December 31, 2010 (the Successor Period), which relate to the periods before and after Crestwood Holdings acquisition of Quicksilver’s ownership interest in Legacy Crestwood (the Crestwood Transaction).

EBITDA and Adjusted EBITDA - We believe that EBITDA and Adjusted EBITDA are widely accepted financial indicators of a company's operational performance and its ability to incur and service debt, fund capital expenditures and make distributions. EBITDA is defined as income before income taxes, plus net interest and debt expense, and depreciation, amortization and accretion expense. In addition, Adjusted EBITDA considers the adjusted earnings impact of our unconsolidated affiliates by adjusting our equity earnings or losses from our unconsolidated affiliates for our proportionate share of their depreciation and interest and the impact of certain significant items, such as unit-based compensation charges, gains and impairments of long-lived assets and goodwill, gains and losses on acquisition-related contingencies, third party costs incurred related to potential and completed acquisitions, certain environmental remediation costs, change in fair value of certain commodity derivative contracts, and other transactions identified in a specific reporting period. EBITDA and Adjusted EBITDA are not measures calculated in accordance with GAAP, as they do not include deductions for items such as depreciation, amortization and accretion, interest and income taxes, which are necessary to maintain our business. EBITDA and Adjusted EBITDA should not be considered an alternative to net income, operating cash flow or any other measure of financial performance presented in accordance with GAAP. EBITDA and Adjusted EBITDA calculations may vary among entities, so our computation may not be comparable to measures used by other companies.

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	Crestwood Equity Partners LP Year Ended December 31, (in millions, except per unit data) Successor Year Ended December 31,					Predecessor
	2014	2013 (1)	2012	2011	Period from October 1, 2010 to December 31, 2010	Period from January 1, 2010 to September 30, 2010
Statement of Income Data:						
Revenues	$3,931.3	$1,426.7	$239.5	$205.8	$31.3	$82.3
Operating income	117.9	28.2	61.4	71.0	5.8	37.5
Income (loss) before income taxes	(9.3)	(49.6)	25.6	43.4	1.1	28.7
Net income (loss)	(10.4)	(50.6)	24.4	42.1	1.8	28.6
Net income attributable to Crestwood Equity Partners LP	56.4	6.7	14.9	7.7	0.7	1.8
Performance Measures:						
Diluted limited partner income per unit: (2)						
From net income	$0.30	$0.06	$0.38	$0.19	$0.02	$0.04
Distributions declared per limited partner unit(3)	$0.55	$0.6925	$1.33	$2.82	$0.705	$2.105