Crestwood Equity Partners LP
Form 10-K
February 26, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

(Exact name of registrant as specified in its charter)	Commission file number	State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)
Crestwood Equity Partners LP	001-34664	Delaware	43-1918951
Crestwood Midstream Partners LP	001-35377	Delaware	20-1647837

811 Main Street, Suite 3400 Houston, Texas	77002
(Address of principal executive offices)	(Zip code)

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

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

Crestwood Equity Partners LP	Common Units representing limited partnership interests, listed on the New York Stock Exchange
Crestwood Midstream Partners LP	None

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

Crestwood Equity Partners LP	None
Crestwood Midstream Partners LP	None

Indicate by check mark if registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act.

Crestwood Equity Partners LP	Yes x No ¨
Crestwood Midstream Partners LP	Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

Crestwood Equity Partners LP	Yes ¨ No x
Crestwood Midstream Partners LP	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.

Crestwood Equity Partners LP	Yes x No ¨
Crestwood Midstream Partners LP	Yes x No ¨

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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).

Crestwood Equity Partners LP	Yes x No ¨
Crestwood Midstream Partners LP	Yes x No ¨

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.

Crestwood Equity Partners LP	x
Crestwood Midstream Partners LP	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.

Crestwood Equity Partners LP	Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨	Emerging growth company ¨
Crestwood Midstream Partners LP	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨	Emerging growth company ¨

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

Crestwood Equity Partners LP	o
Crestwood Midstream Partners LP	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Crestwood Equity Partners LP	Yes ¨ No x
Crestwood Midstream Partners LP	Yes ¨ No x

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2017).

Crestwood Equity Partners LP	$1.1 billion
Crestwood Midstream Partners LP	None

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (February 12, 2018).

Crestwood Equity Partners LP	$26.95 per common unit	71,231,599
Crestwood Midstream Partners LP	None	None

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents are incorporated by reference into the indicated parts of this report:

Crestwood Equity Partners LP	None
Crestwood Midstream Partners LP	None

Crestwood Midstream Partners LP, as a wholly-owned subsidiary of a reporting company, meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this report with the reduced disclosure format as permitted by such instruction.

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FILING FORMAT

This Annual Report on Form 10-K is a combined report being filed by two separate registrants: Crestwood Equity Partners LP and Crestwood Midstream Partners LP. Crestwood Midstream Partners LP is a wholly-owned subsidiary of Crestwood Equity Partners LP. Information contained herein related to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrant.

Item 15 of Part IV of this Annual Report includes separate financial statements (i.e., balance sheets, statements of operations, statements of comprehensive income, statements of partners' capital and statements of cash flows, as applicable) for Crestwood Equity Partners LP and Crestwood Midstream Partners LP. The notes accompanying the financial statements are presented on a combined basis for each registrant. Management's Discussion and Analysis of Financial Condition and Results of Operations included under Item 7 of Part II is presented for each registrant.

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CRESTWOOD MIDSTREAM PARTNERS LP
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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.
ASU	Accounting Standards Update.
Barrels (Bbls)	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.
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.
HP	Horsepower.
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.
MMBbls	One million barrels.
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).
NYPSC	New York State Public Service Commission.
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.

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,” “CEQP,” and similar terms refer to either Crestwood Equity Partners LP itself or Crestwood Equity Partners LP and its consolidated subsidiaries, as the context requires, and (ii) “Crestwood Midstream” and “CMLP” refers to Crestwood Midstream Partners LP and its consolidated subsidiaries Unless otherwise indicated, information contained herein is reported as of December 31, 2017.

Introduction

Crestwood Equity, a Delaware limited partnership formed in March 2001, 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 natural gas and crude oil shale plays across the United States. 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. Crestwood Equity’s common units representing limited partner interests are listed on the NYSE under the symbol “CEQP.”

Crestwood Equity is a holding company. All of our consolidated operating assets are owned by or through our wholly-owned subsidiary, Crestwood Midstream, a Delaware limited partnership. Our consolidated operating assets primarily include:

- natural gas facilities with approximately 2.4 Bcf/d of gathering capacity and 0.5 Bcf/d of processing capacity;
- NGL facilities with approximately 20,000 Bbls/d of fractionation capacity and 3.1 MMBbls of storage capacity, as well as our portfolio of transportation assets (consisting of truck and rail terminals, truck/trailer units and rail cars) capable of transporting approximately 195,000 Bbls/d of NGLs; and
- crude oil facilities with approximately 125,000 Bbls/d of gathering capacity, 1.5 MMBbls of storage capacity, 20,000 Bbls/d of transportation capacity and 160,000 Bbls/d of rail loading capacity.

In addition, through our equity investments in joint ventures, we have ownership interests in:

- natural gas facilities with approximately 0.3 Bcf/d of gathering capacity, 0.2 Bcf/d of processing capacity, 75.8 Bcf of certificated working storage capacity, and 1.5 Bcf/d of transportation capacity; and
- crude oil facilities with approximately 20,000 Bbls/d of rail loading capacity and 380,000 Bbls of working storage capacity.

Our primary business objective is to maximize the value of Crestwood for our unitholders.

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Ownership Structure

The diagram below reflects a simplified version of our ownership structure as of December 31, 2017:

Crestwood Equity. Crestwood Equity GP LLC, which is indirectly owned by Crestwood Holdings LLC (Crestwood Holdings), owns our non-economic general partnership interest. Crestwood Holdings, which is substantially owned and controlled by First Reserve Management, L.P. (First Reserve), also owns approximately 25% of Crestwood Equity's common units and all of its subordinated units as of December 31, 2017.

Crestwood Midstream. Crestwood Equity owns a 99.9% limited partnership interest in Crestwood Midstream and Crestwood Gas Services GP LLC (CGS GP), a wholly-owned subsidiary of Crestwood Equity, owns a 0.1% limited partnership interest in

Crestwood Midstream. Crestwood Midstream GP LLC, a wholly-owned subsidiary of Crestwood Equity, owns the non-economic general partnership interest of Crestwood Midstream.

Simplification Merger (2015). On September 30, 2015, Crestwood Midstream merged with a wholly-owned subsidiary of Crestwood Equity, with Crestwood Midstream surviving as a wholly-owned subsidiary of Crestwood Equity (the Simplification Merger). Prior to the Simplification Merger, Crestwood Equity indirectly owned a non-economic general partnership interest in Crestwood Midstream and 100% of its incentive distribution rights (IDRs), which entitled Crestwood Equity to receive 50% of all distributions paid to Crestwood Midstream's common unit holders in excess of its initial quarterly distribution of $0.37 per common unit. Crestwood Midstream's common units were also listed on the NYSE under the listing symbol "CMLP". Upon becoming a wholly-owned subsidiary of Crestwood Equity as a result of the Simplification Merger, Crestwood Midstream's IDRs were eliminated and its common units ceased to be listed on the NYSE.

Prior to the Simplification Merger, Crestwood Midstream owned all of our operating assets other than the assets comprising our NGL marketing business. Crestwood Operations LLC (Crestwood Operations), a wholly-owned subsidiary of Crestwood Equity, owned and operated the assets comprising our NGL marketing business, consisting mainly of our West Coast NGL assets, our Seymour NGL storage facility, and our NGL transportation terminals and fleet. Upon the closing of the Simplification Merger, Crestwood Equity contributed 100% of its interests in Crestwood Operations to Crestwood Midstream. As a result of this contribution, all of the Company's assets are owned by or through Crestwood Midstream. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2 for a further discussion of the Simplification Merger.

Our Assets

Our financial statements reflect three operating and reporting segments: (i) gathering and processing (G&P) operations; (ii) storage and transportation (S&T) operations; and (iii) marketing, supply and logistics (MS&L) operations. Below is a description of our operating and reporting segments.

Gathering and Processing

Our G&P operations provide gathering and transportation services (natural gas, crude oil and produced water) and processing, treating and compression services (natural gas) to producers in unconventional shale plays and tight-gas plays in North Dakota, West Virginia, Texas, New Mexico, Wyoming and Arkansas. This segment primarily includes our operations and investments that own (i) our crude oil, gas and produced water gathering systems in the Bakken Shale play; (ii) rich gas gathering systems and processing plants in the Bakken, Marcellus, Barnett, Delaware Permian and Powder River Basin Shale plays; and (iii) dry gas gathering systems in the Barnett, Fayetteville and Delaware Permian Shale plays.

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The table below summarizes certain information about our G&P systems (including our equity investments) as of December 31, 2017:

Shale Play (State)	Counties / Parishes	Pipeline (Miles)	Gathering Capacity	2017 Average Gathering Volumes	Compression (HP)	Number of In-Service Processing Plants	Processing Capacity (MMcf/d)	Gross Acreage Dedication
Bakken North Dakota	McKenzie and Dunn	640 (1)	100 MMcf/d - natural gas gathering 125 MBbls/d - crude oil gathering 40 MBbls/d - water gathering	48 MMcf/d - natural gas gathering 80 MBbls/d - crude oil gathering 35 MBbls/d - water gathering	18,000	1	30	150,000
Marcellus West Virginia	Harrison, Barbour and Doddridge	80	875 MMcf/d	423 MMcf/d	131,380	—	—	140,000
Barnett Texas	Hood, Somervell, Tarrant, Johnson and Denton	507	925 MMcf/d	319 MMcf/d	153,465	1	425	140,000
Fayetteville Arkansas	Conway, Faulkner, Van Buren, and White	173	510 MMcf/d	46 MMcf/d	18,670	—	—	143,000
Granite Wash Texas	Roberts	36	36 MMcf/d	10 MMcf/d	10,400	1	36	22,000
Delaware Permian(2) New Mexico/Texas	Eddy (New Mexico) Loving, Reeves, Ward, Culberson (Texas)	189	165 MMcf/d	74 MMcf/d	33,310 (3)	2	75	214,000
Powder River Basin (3) Wyoming	Converse	211	140 MMcf/d	60 MMcf/d	50,895	1	120	358,000

(1) Consists of 262 miles of natural gas gathering pipeline, 183 miles of crude oil gathering pipeline, and 195 miles of produced water gathering pipeline.

(2) Our Delaware Permian assets in New Mexico and Texas are owned by Crestwood Permian Basin Holdings LLC (Crestwood Permian), our 50% equity method investment.

(3) Includes 16,800 HP that is owned and operated by a third party under a compression services agreement.

(4) Our Powder River Basin assets are owned by Jackalope Gas Gathering Services, L.L.C. (Jackalope), our 50% equity method investment.

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.

Bakken

Our Arrow system gathers crude oil, rich 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. Located approximately 60 miles southeast of the COLT Hub, the Arrow system connects to our COLT Hub through Hiland Partners, LP (Hiland) and Andeavor crude oil pipeline systems. The Arrow system includes approximately 640 miles of gathering lines, a 23-acre central delivery point with 266,000 Bbls of crude oil working storage capacity and multiple pipeline take-away outlets, and salt water disposal wells. We are completing construction of a 30 MMcf/d natural gas processing facility (Bear Den) and associated pipelines that began receiving gas in late 2017. Our operations are anchored by long-term gathering contracts with producers who have dedicated over 150,000 acres to the Arrow system, and our underlying contracts largely provide for fixed-fee gathering services with annual escalators for crude oil, natural gas and produced water gathering services.

Marcellus

We own and operate natural gas gathering and compression systems in Harrison, Doddridge and Barbour Counties, West Virginia. These systems consist of 80 miles of low pressure gathering lines and nine compression and dehydrations stations with 131,380 horsepower. Through these systems, we provide midstream services, primarily to Antero Resources Corporation (Antero), under long-term, fixed-fee contracts across two operating areas: our eastern area of operation (East AOD), where we are the exclusive gatherer, and our western area of operation (Western Area), where we provide compression services.

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In the East AOD, we provide gathering, dehydration and compression services, on a fixed-fee basis, to Antero on approximately 140,000 gross acres dedicated pursuant to a 20-year gathering and compression agreement. Under the gathering agreement, Antero provides for an annual minimum volume commitment of 450 MMcf/d in 2018. We gather and ultimately redeliver Antero's production to MarkWest Energy Partners, L.P.'s Sherwood gas processing plant and various regional pipeline systems.

In the Western Area, we provide compression and dehydration services, on a fixed-fee basis, to Antero's gathering facilities predominantly with our West Union and Victoria compressor stations, each with a maximum capacity of 120 MMcf/d. The agreement runs through 2021, subject to Antero's right to extend the contract term for an additional three years, and provides for a minimum volume commitment of approximately 50% of the throughput capacity of each compressor station.

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 pipelines that gather rich gas produced by customers and deliver the volumes to our plants for processing and 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. For the year ended December 31, 2017, our processing plant had a total average throughput of 114 MMcf/d of natural gas with an average NGL recovery of 9,541 Bbls/d. In June 2015, we diverted processing volumes from our Corvette plant to the Cowtown plant but we continue to use the compression facilities at the Corvette plant.

Our Lake Arlington system, which is located in eastern Tarrant County, Texas, consists of a dry 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 dry gas gathering system and a related dehydration, compression and amine treating facility.

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 system (Van Buren County) consists of a gas gathering system and related dehydration and compression facilities. Our Rose Bud system (White County) consists of a gas gathering system. All of our systems gather natural gas produced by customers and deliver customers' gas to unaffiliated pipelines for sale downstream.

Equity Investments

Delaware Permian

In October 2016, Crestwood Infrastructure Holdings LLC (Crestwood Infrastructure), our wholly-owned subsidiary, and an affiliate of First Reserve formed a joint venture, Crestwood Permian, to fund and own a natural gas gathering system (the Nautilus gathering system) and other potential investments in the Delaware Permian. As part of this transaction, we transferred to the Crestwood Permian joint venture 100% of the equity interest of Crestwood Permian Basin LLC (Crestwood Permian Basin), which owns the Nautilus gathering system. We manage the joint venture under a long-term management agreement and we account for our 50% ownership interest in Crestwood Permian under the equity method of accounting.

Crestwood Permian Basin has a long-term agreement with SWEPI LP (SWEPI), a subsidiary of Royal Dutch Shell plc, to construct, own and operate the Nautilus gathering system in SWEPI's operated position in the Delaware Permian. SWEPI has dedicated to Crestwood Permian Basin approximately 100,000 acres and gathering rights for SWEPI's gas production across a large acreage position in Loving, Reeves and Ward Counties, Texas. The initial build-out of the Nautilus gathering system was completed on June 6, 2017, and includes 20 receipt point meters, 60 miles of pipeline, a 24-mile high pressure header system, 10,080 horsepower of compression and a high pressure delivery point. From the date it was placed into service to December 31, 2017, the Nautilus gathering system had an average throughput of 35 MMcf/d. Crestwood Permian Basin provides gathering, dehydration, compression and liquids handling services to SWEPI under a 20-year fixed-fee gathering agreement. In October 2017, Shell Midstream Partners L.P. (Shell Midstream), a subsidiary of Royal Dutch Shell plc, purchased a 50% equity interest in Crestwood Permian Basin.

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On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico Pipeline LLC
(Crestwood New Mexico), our wholly-owned subsidiary that owns our Delaware Basin assets located in Eddy County, New
Mexico. These assets consist of two dry gas gathering systems (Las Animas systems) and one rich gas gathering system and processing plant (Willow Lake system). Our Willow Lake system includes two plants with a combined capacity of 75MMcf/d processing plant, which are supported by a 10-year fixed-fee agreement with Concho Resources Inc. (Concho) and a seven year contract with Mewbourne Oil Co. (Mewbourne). We deconsolidated Crestwood New Mexico as a result of the contribution. In conjunction with this contribution, First Reserve has agreed to contribute to Crestwood Permian the first $151 million of capital cost required to fund the expansion of the Delaware Basin assets, which includes a new processing plant located in Orla, Texas and associated pipelines (Orla processing plant). See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Crestwood Permian.

Powder River Basin

Our G&P segment includes our 50% equity interest in the Jackalope joint venture with Williams Partners LP (Williams), which we account for under the equity method of accounting. The joint venture, operated by Williams, owns the Jackalope gas gathering system, which serves a 358,000 gross acre dedication operated by Chesapeake Energy Corporation (Chesapeake) in Converse County, Wyoming. The Jackalope system consists of approximately 211 miles of gathering pipelines, 50,895 horsepower of compression and a 120 MMcf/d processing plant (Bucking Horse). The system connects to 100 well pads and is supported by a 10-year gathering and processing agreement with Chesapeake that includes minimum revenue guarantees for a five to seven year period. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Jackalope.

The table below summarizes certain contract information of our G&P operations (including our equity investments) as of December 31, 2017:

Shale Play	Type of Services	Type of Contracts[(1)]	Gross Acreage Dedication	Major Customers	Weighted Average Remaining Contract Terms (in years)
Bakken	Gathering - crude oil, natural gas and water	Mixed	150,000	WPX, Bruin E&P Partners, LLC, Rimrock Energy Partners, LLC, XTO Energy, QEP Resources, Inc., Enerplus	8
Marcellus	Gathering	Fixed-fee	140,000	Antero	14
	Compression	Fixed-fee	—	Antero	2
Barnett	Gathering	Mixed	140,000	BlueStone, Devon Energy, Tokyo Gas America Ltd. (Tokyo Gas)	7
	Processing	Mixed	—	BlueStone, Devon Energy, Tokyo Gas	9
	Compression	Mixed	—	BlueStone, Devon Energy, Tokyo Gas	7
Fayetteville	Gathering	Fixed-fee	143,000	BHP Billiton Petroleum (BHP)	7
	Treating	Fixed-fee	—	BHP	7
Granite Wash	Gathering	Fixed-fee	22,000	Sabine Oil and Gas	7
	Processing	Mixed	—	Sabine Oil and Gas	7
Permian	Gathering	Fixed-fee	214,000	Mewbourne, Concho, Marathon Oil Corp, SWEPI	7
	Processing	Mixed	—	Mewbourne, Matador	4

Powder River Basin	Gathering	Fixed-fee	358,000	Chesapeake	10
	Processing	Fixed-fee	—	Chesapeake	10

(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.

Storage and Transportation

Our S&T operations include our COLT Hub, one of the largest crude-by-rail terminals serving Bakken crude oil production, and our equity investments in three joint ventures that own five high-performance natural gas storage facilities with an aggregate certificated working gas storage capacity of approximately 75.8 Bcf, three natural gas pipeline systems with an aggregate firm transportation capacity of 1.5 Bcf/d, and crude oil facilities with approximately 380,000 Bbls of crude oil working storage capacity and 20,000 Bbls/d of rail loading capacity.

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COLT Hub

The COLT Hub consists of our integrated crude oil loading, storage and pipeline terminal located in the heart of the Bakken and Three Forks Shale oil-producing areas in Williams County, North Dakota. It has approximately 1.2 MMBbls of crude oil storage capacity and is capable of loading up to 160,000 Bbls/d. 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 proprietary 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 crude oil gathering systems and the Dakota Access Pipeline (DAPL) interstate pipeline system at the COLT terminal, and the Enbridge Energy Partners, L.P. and Andeavor interstate pipeline systems at Dry Fork. The gathering systems connected to the COLT Hub can deliver up to approximately 350,000 Bbls/d of crude oil to our terminal.

Equity Investments

Below is a description of the S&T assets owned by our joint ventures.

Northeast Storage Facilities. Our storage and transportation segment includes our 50% equity interest in Stagecoach Gas Services LLC (Stagecoach Gas), which we account for under the equity method of accounting. On June 3, 2016, our wholly-owned subsidiary, Crestwood Pipeline and Storage Northeast LLC (Crestwood Northeast) and Con Edison Gas Pipeline and Storage Northeast, LLC (CEGP), a wholly-owned subsidiary of Consolidated Edison, Inc. (Consolidated Edison), formed Stagecoach Gas to own and further develop our natural gas natural gas storage and transportation business located in the Northeast (the NE S&T assets). During 2016, we contributed to the joint venture the entities owning the NE S&T assets, CEGP contributed to the joint venture $975 million in exchange for a 50% equity interest in Stagecoach Gas, and Stagecoach Gas distributed to us the net cash proceeds received from CEGP. We manage the joint venture's operations under a long-term management agreement. We deconsolidated the NE S&T assets as a result of the contribution of these assets to Stagecoach Gas as described above. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Stagecoach Gas.

The Stagecoach Gas joint venture owns and operates four natural gas storage facilities located in New York and Pennsylvania. The facilities are located near major shale plays and demand markets, have low maintenance costs and long useful lives. They have comparatively high cycling capabilities, and their interconnectivity with interstate pipelines offers significant flexibility to customers. These natural gas storage facilities, each of which generates fee-based revenues as of December 31, 2017, include:

- Stagecoach - a FERC certificated 26.2 Bcf multi-cycle, depleted reservoir storage facility owned and operated by a subsidiary of Stagecoach Gas. A 21-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 Millennium Pipeline Company's (Millennium) system.

- Thomas Corners - a FERC-certificated 7.0 Bcf multi-cycle, depleted reservoir storage facility owned and operated by a subsidiary of Stagecoach Gas. An 8-mile, 12-inch diameter pipeline lateral connects the storage facility to TGP's 200 Line, and an 8-mile, 8-inch diameter pipeline lateral connects to Millennium. Thomas Corners is also connected to Dominion Transmission Inc.'s (Dominion) system through the Steuben facility discussed below.

- Seneca Lake - a FERC-certificated 1.5 Bcf multi-cycle, bedded salt storage facility owned and operated by a subsidiary of Stagecoach Gas. A 20-mile, 16-inch diameter pipeline lateral connects the storage facility to the Millennium and Dominion systems.

- Steuben - a FERC-certificated 6.2 Bcf single-cycle, depleted reservoir storage facility owned and operated by a subsidiary of Stagecoach Gas. 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 the Steuben and Thomas Corners storage facilities.

Tres Palacios Storage Facility. Our storage and transportation segment includes our 50.01% equity interest in Tres Palacios Holdings LLC (Tres Holdings), which we account for under the equity method of accounting. Tres Palacios Gas Storage LLC (Tres Palacios), a wholly-owned subsidiary of Tres Holdings, owns a FERC-certificated 34.9 Bcf multi-cycle salt dome natural gas storage facility located in Texas. We manage the joint venture's operations under a long-term management agreement.

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The Tres Palacios natural gas storage facility's 63-mile, dual 24-inch diameter header system (including a 52-mile north pipeline lateral and an approximate 11-mile south pipeline lateral) interconnects with 11 pipeline systems and can receive residue gas from the tailgate of Kinder Morgan Inc.'s (Kinder Morgan) 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. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our ownership interest in Tres Palacios.

The following provides additional information about the natural gas storage facilities of our S&T equity investments as of December 31, 2017:

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; UGI's Sunbury Pipeline,[1] 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
Northeast Storage Total	40.9	423	845	
Tres Palacios	34.9	1,000	2,500	Multiple[3]
Total	75.8	1,423	3,345	

(1) Stagecoach is connected to UGI Energy Services, LLC's (UGI) Sunbury Pipeline and Transcontinental Gas Pipe Line Corporation's (Transco) Leidy Line through the MARC I Pipeline.

(2) Stagecoach Gas has been authorized by the FERC to expand the facility's working gas storage capacity to 2 Bcf.

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

Transportation Facilities. Stagecoach Gas owns three natural gas pipeline systems located in New York and Pennsylvania. These natural gas transportation facilities include:

- North-South Facilities - include compression and appurtenant facilities installed to expand transportation capacity on the Stagecoach north and south pipeline laterals. The bi-directional interstate facilities provide more than 538 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 North-South Facilities and TGP's 300 Line in Bradford County, Pennsylvania, with UGI's Sunbury Pipeline and Transco's Leidy Line, both in Lycoming County, Pennsylvania. The bi-directional pipeline provides more than 925 MMcf/d of firm interstate transportation capacity to shippers. The MARC I Pipeline generates fee-based revenues under a negotiated rate structure authorized by the FERC.

- East Pipeline - a 37.5 mile, 12-inch diameter intrastate natural gas pipeline located in New York, which transports 30 MMcf/d of natural gas from Dominion to the Binghamton, New York city gate. The pipeline runs within three miles of the North-South Facilities' point of interconnection with Millennium. The East Pipeline generates fee-based revenues under a negotiated rate structure authorized by the NYPSC.

Rail Loading Facility. Crestwood Crude Logistics LLC, our wholly-owned subsidiary, has a 50.01% equity interest in Powder River Basin Industrial Complex, LLC (PRBIC), which owns an integrated crude oil loading, storage and pipeline terminal located in Douglas County, Wyoming. PRBIC provides a market for crude oil production from the Powder River Basin. The joint venture, which is operated by our joint venture partner, Twin Eagle Resource Management, LLC (Twin Eagle), sources crude oil production from Chesapeake and other Powder River Basin producers. PRBIC includes 20,000 Bbls/d of rail loading capacity and 380,000 Bbls of crude oil working storage capacity. PRBIC expanded its pipeline terminal to include connections to Kinder Morgan's Double H Pipeline system in July 2015 and Plains All American Pipeline's Rocky Mountain Pipeline system in March 2016. 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 certain contract information associated with the COLT Hub and the assets of our S&T equity investments as of December 31, 2017:

Facility	Type of Services	Type of Contracts(1)(2)	Contract Volumes	Major Customers	Weighted Average Remaining Contract Terms (in years)
COLT	Rail Loading and Transportation	Mixed	31 MBbl/d	U.S. Oil, Flint Hills Resources, Sunoco Logistics	2
NE S&T Joint Venture:					
North-South Facilities	Transportation	Firm	538 MMcf/d	Southwestern Energy, Consolidated Edison, Anadarko Energy Services Company (Anadarko)	2
MARC I Pipeline	Transportation	Firm	925 MMcf/d	Chesapeake, Anadarko, Chief Oil and Gas	3
East Pipeline	Transportation	Firm	30 MMcf/d	NY State Electric & Gas Corp	3
Stagecoach	Storage	Firm	26.3 Bcf	Consolidated Edison, Merrill Lynch Commodities Inc (Merrill Lynch), New Jersey Natural Gas, Repsol Energy North America Corporation (Repsol), Sequent Energy Management	2
Thomas Corners	Storage	Firm	13.0 Bcf	Repsol, Tenaska Gas Storage, LLC	1
Seneca Lake	Storage	Firm	1.5 Bcf	Dominion, NY State Electric & Gas Corp, DTE Energy Trading	2
Steuben	Storage	Firm	9.3 Bcf	PSEG Energy Resources & Trade LLC, Repsol, Pivotal Utility Holdings	1
Tres Palacios Joint Venture	Storage	Firm	28.5 Bcf	Brookfield Infrastructure Group, Anadarko, Exelon, Merrill Lynch, NJR Energy, Repsol	1
PRBIC Joint Venture	Rail Loading	Fixed-fee	10 MBbl/d	Chesapeake	1

(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. Fixed-fee contracts represent contracts in which our customers agree to pay a flat rate based on the amount of commodity delivered.
(2) Mixed contracts include both firm and fixed-fee arrangements.

Marketing, Supply and Logistics

Our MS&L segment includes our supply and logistics business, our storage and terminals business, our West Coast operations and our crude oil, NGL and produced water trucking operations.

Supply and Logistics. Our Supply and Logistics operations are supported by (i) our fleet of rail and rolling stock with 75,000 Bbls/d of NGL transportation capacity, which also includes our rail-to-truck terminals located in Florida, New Jersey, New York, Rhode Island and North Carolina; and (ii) NGL pipeline and storage capacity leased from third parties, including more than 500,000 Bbls of NGL working storage capacity at major hubs in Mt. Belvieu, Texas and Conway, Kansas.

Storage and Terminals. Our NGL Storage and Terminals operations include our Seymour and Bath storage facilities. The Seymour storage facility is located in Seymour, Indiana, and has 500,000 Bbls of underground NGL storage capacity and 29,000 Bbls of aboveground "bullet" storage capacity. The Seymour facility's receipts and deliveries are supported by Enterprise's TEPPCO pipeline, allowing pipeline and truck access. The Bath storage facility is located in Bath, New York and has approximately 2.0 MMBbls of underground NGL storage capacity and is supported by rail and truck terminal facilities capable of loading and unloading 23 rail cars per day and approximately 100 truck transports per day.

West Coast. Our West Coast NGL operations provide processing, fractionation, storage, transportation and marketing services to producers, refiners and other customers. Our facilities located near Bakersfield, California 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 receipt and take-away options. We separate NGLs from natural gas, deliver to local natural gas pipelines, retain NGLs for further processing at our fractionation facility, provide butane isomerization and refrigerated storage services, as well as provide to Western US refineries for motor fuel production. Our isomerization facility chemically changes normal butane to isobutane, which we provide to refineries for motor fuel production. Our operations also consist of wholesale propane assets, primarily including three rail-to-truck terminals located in Hazen, Nevada, Carlin, Nevada, and Shoshoni, Wyoming and a truck terminal located in Salt Lake City, Utah. These terminals are used to provide supply, transportation and storage services to wholesale customers in the western and north central regions of the United States.

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Trucking. Our Trucking operations consist of a fleet of owned and leased trucks with 20,000 Bbls/d of crude oil and produced water transportation capacity and 120,000 Bbls/d of NGL transportation capacity. We provide hauling services to customers in North Dakota, Montana, Wyoming, Texas, New Mexico, Indiana, Mississippi, New Jersey, Ohio, Utah and California.

Customers

For the years ended December 31, 2017, 2016 and 2015, no customer accounted for more than 10% 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, through our consolidated operations and our equity investments, 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:

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.

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.

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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.

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 (i.e., 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 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 the 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.

Regulation

Our operations and investments 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. We cannot predict the extent to which this trend will continue in the foreseeable future or in the long term.

Pipeline and Underground Storage Safety

We are subject to pipeline safety regulations imposed by the U.S. 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 and storage facilities. 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. The integrity management programs govern pipeline operators' actions in high-consequence areas, such as areas of high population and areas unusually sensitive to environmental damage. Specifically, 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, the NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. More recently, in June 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (2016 Pipeline Safety Act) was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities by June 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016, to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act and the 2016 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 pipeline regulations to, among other things: (i) expand the scope of high consequence areas; (ii) strengthen integrity management requirements applicable to existing operators; (iii) 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 (iv) add new regulations to govern underground facilities that are not currently subject to federal regulation. See "We may incur higher costs as a result of pipeline integrity management program testing and additional safety legislation," under Item 1A. Risk Factors for further discussion on PHMSA rulemaking. 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 and investments.

Future environmental regulatory developments, such as more strict environmental laws or regulations, or more stringent enforcement of the existing regulatory requirements could also directly affect our operations and investments. For example, in June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage facilities. These standards will require the use of certain specific emissions control practices, thereby requiring additional controls for pneumatic controllers and pumps, as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, in June 2017, the EPA published a proposed rule to stay certain portions of these 2016 standards for two years and reconsider the entirety of the 2016 standards but has not yet published a final rule and, as a result, the 2016 standards are currently in effect.

States are also expected to implement their own rules, which could be more stringent than federal requirements. In matters that could have an indirect adverse effect on our business by decreasing demand for the services that we offer, the EPA has completed a study of potential adverse impacts that certain drilling methods (including hydraulic fracturing) may have on water quality and public health, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Congress has also considered but not adopted, and several states have

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proposed or enacted, legislation or regulations imposing more stringent or costly requirements for exploration and production companies to develop and produce hydrocarbons.

States are largely preempted by federal law from regulating pipeline safety for interstate pipelines, but most states 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 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 whether a pipeline is a gathering pipeline, and 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. 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 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, the services provided by such facility would be subject to FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, 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 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 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, 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, however, a 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 TRRC, which requires that our NGL pipelines file tariff publications containing all the rules and the 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 New York State Department of Environmental Conservation (NYSDEC) have jurisdiction over the underground storage of NGLs and NGL related well drilling, well conversions and well 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, as well as our proposed storage facility near Watkins Glen.

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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, and determined in August 2011 that the Draft Supplemental Environmental Impact Statement we submitted for the project was complete. In 2012, we modified our brine pond designs in response to local concerns and submitted to the NYSDEC final drawings and plans for our revised project design. The NYSDEC published a draft storage permit in October 2014, and held an issues conference in February 2015, to determine if any significant issues remained that would require an adjudicatory hearing. In September 2016, we further modified our project design (i.e., reduced storage capacity, eliminated truck and rail transportation options, and eliminated brine pond capacity) in response to local concerns and perceptions. In September 2017, the Chief Administrative Law Judge ruled that the opponents of the project failed to raise any issues requiring adjudication. This ruling has been appealed to the NYSDEC Commissioner. As part of the US Salt divestiture, we retained all surface and sub-surface rights necessary to place the Watkins Glen NGL storage development project into service once we receive all required regulatory approvals. We cannot predict with certainty if and when the permitting process will be concluded.

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 so as to not confer undue preference upon any shipper. The transportation of crude oil by common carrier pipelines on an intrastate basis 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. We cannot, however, provide assurance that the FERC will not, at some point, either at the request of other entities or on its own initiative, assert that some or all of our crude oil pipelines are subject to FERC requirements for common carrier pipelines, or are otherwise not exempt from the FERC’s filing or reporting requirements, or that such an assertion would not adversely affect our results of operations. In the event the FERC were to determine that these crude oil pipelines are subject to FERC requirements for common carrier pipelines, or otherwise would not qualify for a waiver from the FERC’s applicable regulatory requirements, we would likely be required to (i) file a tariff with the FERC; (ii) provide a cost justification for the transportation charge; (iii) provide service to all potential shippers without undue discrimination; and (iv) potentially be subject to fines, penalties or other sanctions.

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, during 2016, the NDIC approved additional requirements relating to site construction, underground gathering pipelines and spill containment that became effective on October 1, 2016, while other requirements relating to bonding for underground gathering pipelines, and construction of berms around facilities became effective on January 1, 2017. Additionally, 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, and subsequently modified that order in late 2015. Exploration and production operators in the state may be required to install new equipment to satisfy these goals, and any failure by operators to meet these gas capture percentage goals would subject those operators to production restrictions, which could reduce the amount of commodities we gather on the Arrow system from 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, may be subject to applicable regulation by the Mandan, Hidatsa & Arikara Nation (MHA Nation). An entirely separate and distinct set of laws and regulations may apply to operators and other parties within the boundaries of the Fort Berthold Indian Reservation. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and the Bureau of Land Management (BLM) promulgate and enforce regulations pertaining to oil and gas operations on Native American lands. These regulations include lease provisions, environmental standards, tribal employment 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, Native American tribes possess certain inherent authorities to enact and enforce their own internal laws and regulations as long as such laws and regulations do not supersede or conflict with such federal statutes. These tribal laws and regulations may include various fees, taxes, and requirements to extend preference in employment to tribal members or Indian owned businesses. Further, lessees and operators within a Native American reservation may be subject to the pertinent Native American judiciary system, or barred from litigating matters adverse to the pertinent tribe unless there is a specific waiver of the tribe's sovereign immunity. Therefore, we may be subject to various applicable 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 applicable regulatory requirements, or delays in obtaining necessary approvals or permits necessary to operate on tribal lands, 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 with a Native American reservation. Additionally, we cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way in Native American lands without experiencing significant costs. For example, following a recent decision issued in May 2017 by the Federal Tenth Circuit Court of Appeals that relied, in part, on a previous Federal Eighth Circuit Court of Appeals decision, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Native American landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators.

In recent years, PHMSA and other federal agencies have reviewed the adequacy of transporting Bakken crude oil by rail transport and, as necessary have pursued rules to better assure the safe transport of Bakken crude oil by rail. For example, in May 2015, PHMSA adopted a final rule that includes, among other things, providing new sampling and testing requirements to improve classification of Bakken crude oil transported. Additional proposed and final rules issued by PHMSA in July 2016 and August 2016, respectively, mandate a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029, and may expand the applicability of comprehensive oil spill response plans so that any railroad transporting a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train will have to have a current, comprehensive, written plan. We, as the owner of a Bakken crude loading terminal, may be adversely affected to the extent more stringent rail transport rules result in more significant operating costs in the shipment of Bakken crude oil by rail or as a result of delays or limitations of such shipments.

Natural Gas Storage and Transportation

Our equity investments' natural gas pipelines used in gathering, storage and transportation activities are subject to regulation under NGPSA, and all of our equity investments' crude oil pipelines used in gathering, storage and transportation activities are subject to regulation under HLPSA. On December 14, 2016, PHMSA issued final interim rules that impose new safety related requirements on downhole facilities (including wells, wellbore tubing and casing) of new and existing underground natural gas storage facilities. The final interim rules adopt and make mandatory two American Petroleum Institute Recommend Practices that, among other things, address construction, maintenance, risk-management and integrity-management procedures. PHMSA indicated when it issued the interim final rule that the adoption of these safety standards for natural gas storage facilities represent a first step in a multi-phase process to enhance the safety of underground natural gas storage, with more standards likely forthcoming. Most recently, in response to a petition for reconsideration of the interim final rule received in January 2017, PHMSA published a notice in June 2017, advising that the agency intends to consider the issues raised by the petitioners in a final rule, which it currently expects to issue in 2018. At this time, we cannot predict the impact of any future regulatory actions in this area. To the extent we operate or manage natural gas storage facilities owned by our equity investments, we are evaluating the final interim rules and their potential impact on our equity investments. PHMSA's interim final rules could significantly increase the costs of operating and maintaining natural gas storage facilities.

The interstate natural gas storage and transportation operations of our equity investments are subject to regulation by the FERC under the Natural Gas Act. Subsidiaries of our Stagecoach Gas and Tres Holdings joint ventures 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 (i) rates charged for services and the terms and conditions of service; (ii) the certification and construction of new facilities; (iii) the extension or abandonment of services and facilities; (iv) the maintenance of accounts and records; (v) the acquisition and disposition of facilities; (vi) standards of conduct between affiliated entities; and (vii) 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.

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The rates and terms and conditions of our natural gas storage and transportation equity investments are found in the FERC-approved tariffs of (i) Stagecoach Pipeline & Storage Company LLC (Stagecoach Pipeline), a wholly-owned subsidiary of Stagecoach Gas that owns the Stagecoach natural gas storage facility, the North-South Facilities and the MARC I Pipeline, (ii) Arlington Storage Company, LLC (Arlington Storage), a wholly-owned subsidiary of Stagecoach Gas that owns the Thomas Corners, Seneca Lake and Steuben natural gas storage facilities, and (iii) Tres Palacios, a wholly-owned subsidiary of Tres Holdings that owns the Tres Palacios natural gas storage facility. Stagecoach Pipeline, Arlington Storage and Tres Palacios are authorized to charge and collect market-based rates for storage services, and Stagecoach Pipeline is authorized to charge and collect negotiated rates for transportation services. Market-based and negotiated rate authority allows our equity investments to negotiate rates with individual customers based on market demand. A loss of market-based or negotiated rate authority or any successful complaint or protest against the rates charged or provided by our equity investments could have an adverse impact on our results of operations.

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 approximately $1.2 million per day per violation.

The interstate natural gas storage operations of our equity investments 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 NYSDEC, therefore, regulates aspects of the Stagecoach, Thomas Corners, Seneca Lake and Steuben natural gas storage facilities.

Supply and Logistics

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

Environmental and Occupational Safety and Health Matters

Our operations and investments are subject to stringent federal, state, regional 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 (i) the need to obtain permits to conduct regulated activities; (ii) restrict the types, quantities and concentration of materials that can be released into the environment; (iii) apply workplace health and safety standards for the benefit of employees; (iv) require remedial activities or corrective actions to mitigate pollution from former or current operations; and (v) impose substantial liabilities on us for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the (i) assessment of sanctions, including administrative, civil and criminal penalties; (ii) imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; (iii) occurrence of delays in permitting or the development of projects; and (iv) 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 and investments 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 non-hazardous and 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 and which serves as a legal basis for the EPA to adopt climate change regulatory initiatives relating to greenhouse gas (GHG) emissions;
- 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;

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- 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 or the more detailed Environmental Impact Statements, may be made available for public review and comment;
- The Endangered Species Act, which restricts activities that may affect federally identified endangered or 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 federal environmental laws, as well as their state counterparts, 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.

During 2014, we experienced three releases on our Arrow produced water gathering system that resulted in approximately 28,000 barrels of produced water being released on lands within the boundaries of the Fort Berthold Indian Reservation. In May 2015, we experienced another release of approximately 5,200 barrels of produced water. We have substantially completed our remediation efforts for the spills, and we believe our remediation costs will be recoverable under our insurance policies.

In April 2015, the EPA issued a Notice of Potential Violation (NOPV) under the Clean Water Act relating to the largest of the 2014 water releases. We responded to the NOPV in May 2015, and in April 2017, we entered into an Administrative Order on Consent (the Order) with the EPA. The Order requires us to continue to remediate and monitor the impacted area for no less than four years unless all goals of the Order are satisfied earlier. On December 13, 2017, the EPA and Crestwood signed a Combined Complaint and Consent Agreement (CCCA) whereby we agreed to pay a civil penalty of $49,000 to the EPA and purchase emergency response equipment at an estimated cost of approximately $173,000 for the Three Affiliated Tribes as a Supplemental Environmental Project (SEP). The CCCA and SEP concludes the EPA's penalty phase related to this matter.

In March 2015, we received a grand jury subpoena from the United States Attorney's Office in Bismarck, North Dakota, seeking documents and information relating to the largest of the three 2014 water releases. In September 2017, we received a notice from the United States Department of Justice that it completed the investigation with no charges being filed against us.

In August 2015, we received a notice of violation from the Three Affiliated Tribes' Environmental Division related to our 2014 produced water releases on the Fort Berthold Indian Reservation. The notice of violation imposes fines and requests reimbursements exceeding $1.1 million; however, the notice of violation was stayed in September 2015, upon our posting of a performance bond for the amount contemplated by the notice and pending the outcome of settlement discussions with the EPA related to the NOPV. Although we continue to have productive settlement conversations with the Tribe, we cannot predict if or when we will be able to settle the dispute.

Employees

As of February 9, 2018, we had 954 full-time employees, 298 of which were general and administrative employees and 656 of which were operational. We believe that our relationship with our employees is satisfactory.

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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 or Crestwood Midstream Partners LP, 811 Main Street, Suite 3400, 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, 811 Main Street, Suite 3400, 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, 811 Main Street, Suite 3400, Houston, Texas 77002, Attention: General Counsel. All such communications will be delivered to the director or directors to whom they are addressed.

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, which has historically generated the need for new or expanded midstream infrastructure. 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, although capital investment in certain areas may have increased as crude oil prices improved in throughout 2017 and early 2018, significantly lower commodity prices during the past few years have resulted in an industry-wide reduction in capital expenditures by producers and a slowdown in drilling, completion and supply development efforts. Notwithstanding this market downturn, production volumes of crude oil, natural gas and NGLs have continued to grow (or decline at a slower rate than expected). Similarly 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. Factors expected to impact crude oil demand include the lifting of the United States' crude oil export ban and production cuts and freezes implemented by Organization of the Petroleum Exporting Countries (OPEC) members and Russia. 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;
- 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, including the recent decline in crude oil and natural gas prices, 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;
- shareholder activism and activities by non-governmental organizations to limit sources of funding for the energy sector or restrict the exploration, development and production of oil and gas:
- 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 low commodity prices, as the industry is currently experiencing, could adversely impact storage and transportation values for some period of time until market conditions adjust. With West Texas Intermediate crude oil prices ranging from $42.53 to $60.42 per barrel in 2017, the sustainability of recent prices improvements and longer-term oil prices cannot be predicted. 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 commodity prices remain low, resulting in a prolonged period of reduced midstream infrastructure development and service requirements to customers.

Our business strategy depends on our ability to provide increased services to our customers and develop growth projects that can be financed appropriately. We may be unable to complete successful, accretive growth projects 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 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.

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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, processing plant 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.

Our ability to finance new growth projects and make capital expenditures may be limited by our access to the capital markets or ability to raise investment capital at a cost of capital that allows for accretive midstream investments.

The significant decline in energy commodity prices in recent years has led to an increased concern by energy investors regarding the future outlook for the industry. This has resulted in a historic decline in equity and debt valuations in the publicly traded capital markets as well as increased trading volatility. As a result, our publicly traded common units experienced a decrease in value, primarily during 2015 and 2016, with a corresponding increase in yield resulting in a higher cost of capital than we have historically experienced. Our growth strategy depends on our ability to identify, develop and contract for new growth projects and raise the investment capital, at a reasonable cost of capital, required to generate accretive returns from the growth project. This trend may continue and could negatively impact our ability to grow for any of the following reasons:

- access to the public equity and debt markets for partnerships of similar size to us may limit our ability to raise new equity and debt capital to finance new growth projects;
- if market conditions deteriorate below current levels, it is unlikely that we could issue equity at costs of capital that would enable us to invest in new growth projects on an accretive basis; or
- we cannot raise financing for such projects or acquisitions on economically acceptable terms.

The growth projects we complete may not perform as anticipated.

Even if we complete growth projects that we believe will be strategic and accretive, such 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, 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 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 and investments 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, compression facilities and processing plants owned by third parties for us to move gas off our systems; (ii) our crude oil gathering systems depend on third-party

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pipelines to move crude to demand markets or rail terminals and 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 revenues from a limited number of oil and gas producers. If as a result of market conditions, certain of our producer customers levered to shale production reduce capital spending (or continue capital spending levels lower than historical levels) and/or shut in production for economic reasons, this could result in lower revenues for us. In the event that market conditions deteriorate, this could lead to the loss of a significant customer, which could also cause a significant decline in our revenues. In addition, to the extent our producer customers have weathered the challenges of lower commodity prices over the past few years, we cannot provide any assurance that they will remain viable over a longer period of lower commodity prices.

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

Energy commodity prices have declined substantially since 2014 due to a wide range of factors, including a continuing growth of supply, slowdown or decline in demand, and challenges in economic, financial and monetary markets. Sustained low natural gas, NGL and crude oil prices have recently negatively impacted natural gas and oil exploration and production activity levels industry-wide and in the areas we operate. A continued slowdown in activity can result in a decline in the production of hydrocarbons over time, resulting in reduced throughput on our systems, plants, trucks 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.

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 effect 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.

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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.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flows and results of operations.

Many of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flows from operations, the incurrence of debt or the issuance of equity. The combination of the reduction of cash flows resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facility and the lack of availability of debt or equity financing may result in a significant reduction of customers' liquidity and limit their ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

Our marketing, supply and logistics operations 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 marketing, supply and logistics operations 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 marketing, supply and logistics operations 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 marketing, supply and logistics operations. 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 marketing, supply and logistics operations 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.

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Changes in future business conditions could cause recorded long-lived assets and goodwill to become further impaired, and our financial condition and results of operations could suffer if there is an additional impairment of long-lived assets and goodwill.

We continually monitor our business, the business environment and the performance of our operations to determine if an event has occurred that indicates that a long-lived asset may be impaired. If an event occurs, which is a determination that involves judgment, we may be required to utilize cash flow projections to assess our ability to recover the carrying value of our assets based on our long-lived assets' ability to generate future cash flows on an undiscounted basis. This differs from our evaluation of goodwill, which is evaluated for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than the carrying amount. This evaluation requires us to compare the fair value of each of our reporting units primarily utilizing discounted cash flows, to its carrying value (including goodwill). If the fair value exceeds the carrying value amount, goodwill of the reporting unit is not considered impaired.

Under GAAP, during the years ended December 31, 2017, 2016 and 2015, we were required to record $121.0 million, $194.0 million and $2,223.8 million of long-lived asset and goodwill impairments related to certain of our reporting units because changes in circumstances or events (of which one of the several indicators of impairment was considered jointly is a significant and other than temporary decrease in our market capitalization) indicated that the carrying values of such assets exceeded their fair value and were not recoverable.

Our long-lived assets and goodwill impairment analyses are sensitive to changes in key assumptions used in our analysis, such as expected future cash flows, the degree of volatility in equity and debt markets and our unit price. If the assumptions used in our analysis are not realized, it is possible a material impairment charge may need to be recorded in the future. We cannot accurately predict the amount and timing of any impairment of long-lived assets or goodwill. Further, as we work toward a turnaround of our business, we will need to continue to evaluate the carrying value of our goodwill. Any additional impairment charges that we may take in the future could be material to our results of operations and financial condition. For a further discussion of our long-lived assets and goodwill impairments, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

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 $1.5 billion of long-term debt outstanding as of December 31, 2017. 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:

- 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;

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- 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 investments, or cause 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 facility and indentures governing our senior notes could adversely affect our business, financial condition, results of operations and ability to make distributions.

Our revolving credit facility and indentures governing our senior notes 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 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 facility contains covenants which requires us to maintain certain financial ratios such as (i) a net debt to consolidated EBITDA ratio (as defined in the credit agreement) of not more than 5.50 to 1.0; (ii) a consolidated EBITDA to consolidated interest expense ratio (as defined in our credit agreement) of not less than 2.50 to 1.0, and (iii) a senior secured leverage ratio (as defined in its credit agreement) of not more than 3.75 to 1.0.

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 property (outside of New York) and personal property. None of our equity investments have guaranteed, and none of the assets of our equity investments secure, our obligations under our revolving credit facility.

The provisions of our credit agreement and indentures governing our senior notes 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 facility or indentures governing our senior notes could result in events of default, which could enable our lenders or holders of our senior notes, subject to the terms and conditions of our credit agreement or indentures, as applicable, 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 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 facility and indentures governing our senior notes.

Our credit agreement and indentures governing our senior notes contain provisions relating to change of control of Crestwood Equity's general partner. If these provisions are triggered, our outstanding 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 the revolving credit facility would have the right to foreclose on our assets and holders of our senior notes would be entitled to require us to repurchase all or a portion of our notes at a purchase price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of such repurchase, which would have a material adverse effect on us. There is no restriction on our ability or the ability of Crestwood Equity's general partner or its parent companies to enter into a transaction which would trigger the change of control provision. In certain circumstances, the control of our general partner may be transferred to a third party without unitholder consent, and this may be considered a change in control under our revolving credit facility and senior notes. Please read "The control of our general partner may be transferred to a third party without unitholder consent."

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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, we have used cash flow from operations, borrowings under our revolving credit facilities and issuances of debt or equity to fund our capital programs, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our operations to fund growth. If our cash flow from operations decreases or distributions from our equity investments decrease 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 and the distributions we receive from subsidiaries are 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 operations, 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 these executives, or the loss of key field employees operating in competitive markets, 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.

We operate joint ventures that may limit our operational flexibility.

We conduct a meaningful portion of our operations through joint ventures (including our Crestwood Permian, Jackalope, PRBIC, Stagecoach Gas and Tres Palacios joint ventures), and we may enter into 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 required to offer business opportunities to the joint venture, or rights of participation to other joint venture members, participants in certain areas of mutual interest.

In addition, 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. The performance and ability of our joint venture partners 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.

Moreover, our decision to operate aspects of our business through joint ventures could limit our ability to consummate strategic transactions. Similarly, due to the perceived challenges of existing joint ventures, companies like ours that fund a considerable portion of their operations through joint ventures may be less attractive merger or take-over candidates. We cannot provide any assurance that our operating model will not negatively affect the value of our common units.

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

Our primary exposure to market risk occurs at the time contracts expire and are subject to renegotiation and renewal. As of December 31, 2017, the weighted average remaining term of our consolidated portfolio of natural gas gathering contracts is approximately 10 years, and our consolidated portfolio of crude oil gathering contracts is approximately nine 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.

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, including our joint ventures, are subject to extensive regulation by federal, state and local regulatory authorities. For example, because Stagecoach Gas transports natural gas in interstate commerce and stores natural gas that is transported in interstate commerce, Stagecoach Gas' 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 the 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 the FERC. Additionally, rate increases proposed by a regulated pipeline or storage provider may be

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challenged and such increases may ultimately be rejected by the FERC. Stagecoach Gas has authority from the FERC to charge and collect (i) market-based rates for interstate storage services provided at the Stagecoach, Thomas Corners, Seneca Lake and Steuben facilities and (ii) negotiated rates for interstate transportation services provided by the North-South Facilities and MARC I Pipeline. The FERC has authorized Tres Palacios to charge and collect market-based rates for interstate storage services provided by its natural gas facilities. The 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 our joint ventures will be allowed to continue to operate under such rate structures for the remainder of their assets' operating lives. Any successful challenge against rates charged for their storage and transportation services, or their 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.

There can be no assurance that the 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 approximately $1.2 million 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 health and 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 worker health and safety aspects of our operations, the discharge of materials into the environment and 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, the occurrence of delays in permitting or development of projects 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

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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. For example, in October 2015, the EPA issued a final rule under the federal Clean Air Act lowering the United States NAAQS for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either “attainment/unclassifiable” or “unclassifiable” but has not yet issued non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule. States are also expected to adopt regulations implementing the NAAQS rule that may be more stringent than the federal standards. In another example, the EPA and U.S. Army of Corps of Engineers (Corp) published a final rule in June 2015 that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, but legal challenges to this rule followed and the rule has been stayed nationwide, with the U.S. Supreme Court accepting review of this rule in January 2017 to determine whether jurisdiction resides with the federal district or appellate courts. Subsequently, the EPA and the Corps have proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act’s jurisdiction, and published a proposed rule in November 2017 specifying that the contested May 2015 rule would not take effect until two years after the November 2017 proposed rule is finalized and published in the Federal Registrar. As a result, future implementation of the June 2015 rule is uncertain at this time but to the extent any rule expands the scope of the Clean Water Act’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Our compliance with these or other new or amended legal requirements could result in our incurring significant additional expense and operating delays or restrictions with respect to our operations, which may not be fully recoverable from customers and, thus, could reduce net income. Our customers may similarly incur increased costs or restrictions that may limit or decrease those customers’ operations and have an indirect material adverse effect on our business.

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

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted regulations to restrict emissions of GHGs 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 GHGs 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 GHG 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 as well as 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.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage facilities. These standards require the use of certain equipment specific emissions control practices, require additional controls for pneumatic controllers and pumps as well as compressors, and impose leak detection and repair requirements for natural gas compressor and booster stations. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on public lands. However, in October 2017, the BLM published a proposed rule that would temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019. These rules and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our and our customers’ operations and could delay or curtail our customers’ activities, which could adversely affect our business. On an international level, the United States is one of numerous nations that prepared an international climate change agreement in Paris, France in December 2015, requiring member countries to

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review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris agreement” was signed by the United States in April 2016 and became effective in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but does include pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us and our customers to incur increased compliance and 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. Moreover, any such future laws and regulations that limit emissions of GHGs or that otherwise promote the use of renewable fuels could adversely affect demand for the natural gas our customers produce, which could thereby reduce demand for our services and adversely affect our business. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. In addition, recent non-governmental activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

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, new legislation or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital costs, operational delays and costs of operations. For example, the 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. More recently, in June 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA’s statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities by June 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

With regard to storage facilities, following the leak at a natural gas storage facility, in February 2016, PHMSA issued an advisory bulletin for natural gas storage facility operators, recommending that they review operations to identify the potential leaks and failures caused by corrosion, chemical or mechanical damage, or other material deficiencies in equipment; review storage facility locations and operations of shut-off and isolation systems, and comply with state regulations governing the permitting, drilling, completion, and operation of storage wells, and recommending the voluntary implementation of certain industry recognized recommended practices for natural gas storage facilities. Further in December 2016, PHMSA issued final interim rules that impose new safety-related requirements on downhole facilities (including wells, wellbore tubing and casing) of new and existing underground natural gas storage facilities. The final interim rules adopt and make mandatory two American Petroleum Institute Recommend Practices (API RP 1170 and 1171) that, among other things, address construction, maintenance, risk-management and integrity-management procedures. PHMSA indicated when it issued the interim final rule

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that the adoption of these safety standards for natural gas storage facilities represent a first step in a multi-phase process to enhance the safety of underground natural gas storage, with more standards likely forthcoming. Most recently, in response to a petition for reconsideration of the interim final rule received in January 2017, PHMSA published a notice on June 20, 2017, advising that the agency intends to consider the issues raised by the petitioners in a final rule, which it currently expects to issue in 2018. At this time, we cannot predict the impact of any future regulatory actions in this area.

In January 2017, PHMSA issued a final rule that amends its pipeline safety regulations for the design, construction, testing, operation and maintenance of hazardous liquids pipelines. The final rule imposes more stringent standards that determine how operators repair aging and high-risk infrastructure, increase the frequency of tests that assess pipeline conditions, and require operators to report more operating and safety data. Among other things, the final rule: (i) extends an operator’s reporting requirements to gravity and hazardous liquids gathering pipelines; (ii) requires operators to inspect pipelines in areas affected by extreme weather and similar events within a certain timeframe; (iii) impose new requirements to periodically “pig” transmission pipelines in areas outside of high consequence areas; (iv) broadens the requirement for the use of leak detection systems; and (v) increases the use of inline inspection tools. However, the date of implementation of this final rule by publication in the Federal Registrar remains uncertain following the January 2017 change in Presidential administrations.

We are evaluating PHMSA’s new rules, and we cannot predict the precise impact that compliance with the new rules will have on our business. The new rules may, among other things, require us or our joint ventures to install new or modified safety controls, undertake additional capital projects or conduct maintenance programs on an expedited basis. The costs of complying with the new PHMSA rules, as well as other rules under consideration by PHMSA or other agencies, could have a material adverse effect on our cash flows and results of operations.

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 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.

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 have experienced releases on our Arrow water gathering system 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 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 and preferred unitholders.

We may not have sufficient cash each quarter to pay quarterly distributions to our common unitholders or, alternatively, we may reallocate a portion of our available cash to debt repayment or capital investment. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, distributions received from our joint ventures, and payments of fees and expenses as well as decisions the board of directors makes regarding acceptable levels of debt or the desire to invest in new growth projects. Our board typically reviews these factors on a quarterly basis. Before we pay any cash distributions on our preferred and 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 and, to the extent we are unable to declare and pay fixed cash distributions on our preferred units, we cannot make cash distributions to our common unitholders until all payments accruing on the preferred units have been repaid.

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

- the rates charged for services and the amount of services customers purchase, 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;
- our ability to access the capital markets for additional investment capital; and
- acceptable levels of debt, liquidity and/or leverage.

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; 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.

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Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow given the current trends existing in the capital markets.

Since 2014, the dramatic decrease in commodity prices has negatively impacted the equity and debt markets resulting in limitations on our ability to access the capital markets for new growth capital at a reasonable cost of capital. Historically, we have distributed all of our available cash to our preferred and common unitholders on a quarterly basis and relied upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. If the current capital market trends persist, we may be unable to finance growth externally by accessing the capital markets, and may have to depend on a reallocation of our cash distributions to reduce debt and/or invest in new growth projects. In addition, we may dispose of assets to reduce debt and/or invest in new growth projects, which can impact the level of our cash distributions.

In the event we continue to distribute all of our available cash or decide to reallocate cash to debt reduction, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we decide to reallocate cash to debt reduction or invest in new capital projects, we may be unable to maintain or increase our per unit distribution level. Subject to certain restrictions that apply if we are not able to pay cash distributions to our preferred unitholders, 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 unit holders.

We may issue additional common units without common unitholder approval, which would dilute existing common unit holder 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.

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 effectively chosen by Crestwood Holdings, the general partner and only voting member of Holdings LP, the sole member of our general partner. 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.

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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 (including distributions from joint ventures) 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, including cash flow from reserves and working capital or other borrowings and cash distributions received from our joint ventures, 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 its common units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units. Additionally, Crestwood Holdings may pledge or hypothecate its common units or is interest in Crestwood Holdings LP.

As of December 31, 2017, Crestwood Holdings and its affiliates beneficially held an aggregate of 17,908,700 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. Additionally, Crestwood Holdings may pledge or hypothecate its common units or its interest in Crestwood Holdings LP (Holdings LP), the sole member of our general partner, or its subsidiaries. Such pledge or hypothecation may include terms and conditions that might result in an adverse impact on the trading price of our common units.

Our preferred units contain covenants that may limit our business flexibility.

Our preferred units contain covenants preventing us from taking certain actions without the approval of the holders of a majority or a super-majority of the preferred units, depending on the action as described below. The need to obtain the approval of holders of the preferred units before taking these actions could impede our ability to take certain actions that management or our board of directors may consider to be in the best interests of its unit holders. The affirmative vote of the then-applicable voting threshold of the outstanding preferred units, voting separately as a class with one vote per preferred unit, shall be necessary to amend our partnership agreement in any manner that (i) alters or changes the rights, powers, privileges or preferences or duties and obligations of the preferred units in any material respect; (ii) except as contemplated in the

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partnership agreement, increases or decreases the authorized number of preferred units; or (iii) otherwise adversely affects the preferred units, including without limitation the creation (by reclassification or otherwise) of any class of senior securities (or amending the provisions of any existing class of partnership interests to make such class of partnership interests a class of senior securities). In addition, our partnership agreement provides certain rights to the preferred unit holders that could impair our ability to consummate (or increase the cost of consummating) a change-in-control transaction, which could result in less economic benefits accruing to our common unit holders.

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 and various lenders (Holdings Credit Agreement). In the event of a default by Crestwood Holdings 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. In addition, such a change of control could result in our indebtedness becoming due. Please read "A change of control could result in us facing substantial repayment obligations under our revolving credit facility and senior notes."
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 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

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- 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, 2017, the directors and executive officers of our general partner owned approximately 6% of our common units.
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 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.
Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes.
Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.
If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate. Distributions to our 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 as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.
Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for 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.
The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly applied on a retroactive basis.
The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax

purposes.

In addition, in January 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code were published in the Federal Registrar. The final regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the final regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

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

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.

We have not 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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders behalf.

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

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, a unitholder may be allocated taxable income and gain resulting from the sale and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” being allocated to our unitholders as taxable income without any increase in our cash available for distribution. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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. 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.

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. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for business interest is limited to the sum our business interest income and 30% of our adjusted taxable income. For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Tax-exempt entities face unique tax issues from our owning common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cut and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interest in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

We will treat each purchaser of our 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 our common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we 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 our common units and could have a negative impact on the value of our 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 (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary

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item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (i.e., 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.

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

In addition to 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 Kansas City, Missouri.

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.

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

Crestwood Equity. Crestwood Equity's 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
2017			
December 31, 2017	$22.15	$26.10	$ 0.600
September 30, 2017	22.30	26.65	0.600
June 30, 2017	20.00	27.35	0.600
March 31, 2017	24.35	28.30	0.600
2016			
December 31, 2016	$18.51	$25.70	$ 0.600
September 30, 2016	18.67	22.22	0.600
June 30, 2016	10.40	23.59	0.600
March 31, 2016	7.90	21.56	0.600

The last reported sale price of Crestwood Equity's common units on the NYSE on February 12, 2018, was $26.95. As of that date, Crestwood Equity had 71,231,599 common units issued and outstanding, which were held by 259 unitholders of record.

Distribution Policy

Preferred Units. We are required to make quarterly distributions to our preferred unitholders. The holders of the Preferred Units are entitled to receive fixed quarterly distributions of $0.2111 per unit. Through the quarter ending September 30, 2017 (the Initial Distribution Period), distributions on the Preferred Units could be made in additional Preferred Units, cash, or a combination thereof, at our election. Through and for the quarter ended June 30, 2017, we paid distributions on our Preferred Units through the issuance of additional Preferred Units. The number of units distributed was calculated as the fixed quarterly distribution of $0.2111 per unit divided by the cash purchase price of $9.13 per unit. We accrued the fair value of such distribution at the end of the quarterly period and adjusted the fair value of the distribution on the date the additional Preferred Units were distributed. Distributions on the Preferred Units following the Initial Distribution Period will be paid in in cash unless, subject to certain exceptions, (i) there is no distribution being paid on our common units; and (ii) our available cash (as defined in our partnership agreement) is insufficient to make a cash distribution to our Preferred Unit holders. If we fail to pay the full amount payable to our Preferred Unit holders in cash following the Initial Distribution Period, then (x) the fixed quarterly distribution on the Preferred Units will increase to $0.2567 per unit, and (y) we will not be permitted to declare or make any distributions to our common unitholders until such time as all accrued and unpaid distributions on the Preferred Units have been paid in full in cash. In addition, if we fail to pay in full any Preferred Distribution (as defined in our partnership agreement), the amount of such unpaid distribution will accrue and accumulate from the last day of the quarter for which such distribution is due until paid in full, and any accrued and unpaid distributions will be increased at a rate of 2.8125% per quarter.

Common Units. Crestwood Equity makes quarterly distributions to its 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, including but not limited to, debt repayments, unit buybacks or capital investment;
- 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;

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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 revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to its partners.

On February 14, 2018, Crestwood Equity paid a distribution of $0.60 per limited partner unit ($2.40 per limited partner unit on an annualized basis) to its unitholders of record on February 7, 2018.

Issuer Purchases of Equity Securities

For the year ended December 31, 2017, we relinquished 206,600 common units to cover payroll taxes upon the vesting of restricted units.

Equity Compensation Plan Information

The following table sets forth in tabular format, a summary of the Crestwood Equity equity compensation plan information as of December 31, 2017:

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	—	$ —	4,157,742
Total	—	$ —	4,157,742

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Item 6. Selected Financial Data

Crestwood Midstream. This information has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Crestwood Equity. Crestwood Equity's 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, 2017 and balance sheet data as of December 31, 2017 and 2016 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, 2014 and the balance sheet data as of December 31, 2015, 2014 and 2013 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.

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. We believe that EBITDA and Adjusted EBITDA are useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. EBITDA is defined as income before income taxes, plus debt-related costs (interest and debt expense, net, and gain (loss) on modification/extinguishment of debt) and depreciation, amortization and accretion expense. Adjusted EBITDA considers the adjusted earnings impact of our unconsolidated affiliates by adjusting our equity earnings or losses from our unconsolidated affiliates to reflect our proportionate share (based on the distribution percentage) of their EBITDA, excluding impairments. Adjusted EBITDA also considers the impact of certain significant items, such as unit-based compensation charges, gains and losses on long-lived assets, 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, certain costs related to our historical cost saving initiatives, the change in fair value of commodity inventory-related derivative contracts, costs associated with our 2017 realignment of our Marketing, Supply and Logistics operations and related consolidation and relocation of our corporate offices, and other transactions identified in a specific reporting period. The change in fair value of commodity inventory-related derivative contracts is considered in determining Adjusted EBITDA given that the timing of recognizing gains and losses on these derivative contracts differs from the recognition of revenue for the related underlying sale of inventory to which these derivatives relate. Changes in the fair value of other derivative contracts is not considered in determining Adjusted EBITDA given the relatively short-term nature of those derivative contracts. 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 as alternatives 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,				
	2017	2016	2015	2014	2013 [1]
	(in million, except per unit data)				
Statement of Income Data:					
Revenues	$3,880.9	$2,520.5	$2,632.8	$3,931.3	$1,426.7
Operating income (loss)	(79.4)	(108.7)	(2,084.8)	117.9	28.2
Loss before income taxes	(167.4)	(191.8)	(2,305.1)	(9.3)	(49.6)
Net loss	(166.6)	(192.1)	(2,303.7)	(10.4)	(50.6)
Net income (loss) attributable to Crestwood Equity Partners LP	(191.9)	(216.3)	(1,666.9)	56.4	6.7
Performance Measures:					
Diluted net income (loss) per limited partner unit: [2]	$(3.64)	$(3.55)	$(54.00)	$3.30	$0.59
Distributions declared per limited partner unit[3]	$2.40	$3.175	$5.50	$5.50	$6.925
Other Financial Data:					
EBITDA (unaudited)	$161.4	$152.9	$(1,844.9)	$403.1	$196.2
Adjusted EBITDA (unaudited)	395.4	455.6	527.4	495.9	297.7
Net cash provided by operating activities	255.9	346.1	440.7	283.0	188.3
Net cash provided by (used in) investing activities	38.7	867.2	(212.7)	(483.0)	(1,042.9)
Net cash provided by (used in) financing activities	(294.9)	(1,212.2)	(236.3)	203.6	859.7
Balance Sheet Data:					
Property, plant and equipment, net	$1,820.8	$2,097.6	$3,310.8	$3,893.8	$3,905.3
Total assets	4,284.9	4,448.9	5,762.8	8,421.7	8,476.0
Total debt, including current portion	1,492.2	1,523.7	2,502.9	2,356.8	2,218.8
Other long-term liabilities[4]	104.7	44.6	47.5	47.2	140.4
Partners' capital	2,180.5	2,539.0	2,946.9	5,584.5	5,508.6

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	Crestwood Equity Partners LP Year Ended December 31, (in millions)				
	2017	2016	2015	2014	2013 [1]
Reconciliation of Net Income to EBITDA and Adjusted EBITDA:					
Net loss	$(166.6)	$(192.1)	$(2,303.7)	$(10.4)	$(50.6)
Depreciation, amortization and accretion	191.7	229.6	300.1	285.3	167.9
Interest and debt expense, net	99.4	125.1	140.1	127.1	77.9
(Gain) loss on modification/extinguishment of debt	37.7	(10.0)	20.0	—	—
Provision (benefit) for income taxes	(0.8)	0.3	(1.4)	1.1	1.0
EBITDA	161.4	152.9	(1,844.9)	403.1	196.2
Unit-based compensation charges	25.5	19.2	19.7	21.3	17.4
(Gain) loss on long-lived assets, net[5]	65.6	65.6	821.2	1.9	(5.3)
Goodwill impairment[6]	38.8	162.6	1,406.3	48.8	4.1
Loss on contingent consideration[7]	57.0	—	—	8.6	31.4
(Earnings) loss from unconsolidated affiliates, net[8]	(47.8)	(31.5)	60.8	0.7	0.1
Adjusted EBITDA from unconsolidated affiliates, net	80.3	61.1	25.3	6.9	2.5
Change in fair value of commodity inventory-related derivative contracts	2.2	14.1	5.4	(10.3)	10.7
Significant transaction and environmental-related costs and other items[9]	12.4	11.6	33.6	14.9	40.6
Adjusted EBITDA	$395.4	$455.6	$527.4	$495.9	$297.7

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	Crestwood Equity Partners LP Year Ended December 31,				
	2017	2016	2015	2014	2013 [1]
	(in millions)				
Reconciliation of Net Cash Provided by Operating Activities to EBITDA and Adjusted EBITDA:					
Net cash provided by operating activities	$255.9	$346.1	$440.7	$283.0	$188.3
Net changes in operating assets and liabilities	(0.3)	(57.9)	(98.0)	73.8	(19.6)
Amortization of debt-related deferred costs, discounts and premiums	(7.2)	(6.9)	(8.9)	(8.5)	(9.2)
Interest and debt expense, net	99.4	125.1	140.1	127.1	77.9
Market adjustment on interest rate swaps	—	—	0.5	2.7	1.7
Unit-based compensation charges	(25.5)	(19.2)	(19.7)	(21.3)	(17.4)
Gain (loss) on long-lived assets, net[5]	(65.6)	(65.6)	(821.2)	(1.9)	5.3
Goodwill impairment[6]	(38.8)	(162.6)	(1,406.3)	(48.8)	(4.1)
Loss on contingent consideration[7]	(57.0)	—	—	(8.6)	(31.4)
Earnings (loss) from unconsolidated affiliates, net, adjusted for cash distributions received	0.1	(7.6)	(73.6)	(0.7)	(0.1)
Deferred income taxes	2.1	3.1	3.6	5.2	2.8
Provision (benefit) for income taxes	(0.8)	0.3	(1.4)	1.1	1.0
Other non-cash income (expense)	(0.9)	(1.9)	(0.7)	—	1.0
EBITDA	161.4	152.9	(1,844.9)	403.1	196.2
Unit-based compensation charges	25.5	19.2	19.7	21.3	17.4
(Gain) loss on long-lived assets, net[5]	65.6	65.6	821.2	1.9	(5.3)
Goodwill impairment[6]	38.8	162.6	1,406.3	48.8	4.1
Loss on contingent consideration[7]	57.0	—	—	8.6	31.4
(Earnings) loss from unconsolidated affiliates, net[8]	(47.8)	(31.5)	60.8	0.7	0.1
Adjusted EBITDA from unconsolidated affiliates, net	80.3	61.1	25.3	6.9	2.5
Change in fair value of commodity inventory-related derivative contracts	2.2	14.1	5.4	(10.3)	10.7
Significant transaction and environmental-related costs and other items[9]	12.4	11.6	33.6	14.9	40.6
Adjusted EBITDA	$395.4	$455.6	$527.4	$495.9	$297.7

(1) Financial data presented for periods prior to June 19, 2013, solely reflect the operations of Legacy Crestwood GP. Financial data for periods subsequent to June 19, 2013, represent the consolidated operations of Crestwood Equity.

(2) The weighted average number of units outstanding is calculated based on the presumption that the common and subordinated units issued to acquire Legacy Crestwood GP (the accounting predecessor) were outstanding for the entire period prior to the June 19, 2013 acquisition. On the date of the acquisition, all of our limited partner units were considered outstanding. In addition, on November 23, 2015, CEQP completed a 1-for-10 reverse split of its common units. The accounting standards related to earnings per share requires an entity to restate earnings per share when a stock dividend or stock split occurs, and as such, the earnings per unit for the years ended December 31, 2014 and 2013, were restated to reflect the 1-for-10 reverse split.

(3) Reported amounts include the fourth quarter distributions, which are paid in the first quarter of the subsequent year.

(4) Other long-term liabilities primarily include our capital leases, asset retirement obligations, loss on contingent consideration, net and the fair value of unfavorable contracts recorded in purchase accounting.

(5) During 2017, we recognized a gain of approximately $33.6 million from the sale of US Salt. For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3. During 2016, we recorded a loss of approximately $32.4 million on the deconsolidation of our NE S&T assets. For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Notes 2 and 6. During

2014, we recorded a gain of approximately $30.6 million on the sale of our investment in Tres Palacios. In addition, during 2017, 2015 and 2014, we recorded property, plant and equipment impairments of approximately $81.4 million, $501.7 million and $13.2 million. During 2017, 2016, 2015 and 2014, we recorded intangible asset impairments of approximately $0.8 million, $31.4 million, $316.6 million and $21.3 million. For a further discussion, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Critical Accounting Estimates" and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

(6) For a further discussion of our goodwill impairments recorded during 2017, 2016, 2015 and 2014, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Critical Accounting Estimates" and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

(7) During 2017, the loss on contingent consideration related to our obligation to CEGP due to our expectation of certain criteria on growth capital projects not being met by Stagecoach Gas. For a further discussion, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6. During 2014 and 2013, we recorded a loss on contingent consideration which reflects the fair value of an earn-out premium associated with the original acquisition of our Marcellus G&P assets from Antero in 2012.

(8) During 2015, we recorded impairments of our PRBIC and Jackalope equity investments of approximately $23.4 million and $51.4 million. For a further discussion of these impairments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Critical Accounting Estimates" and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

(9) Significant transaction and environmental-related costs and other items primarily include costs incurred related to the Simplification Merger and other merger, acquisition and joint venture transactions, as well as costs associated with our historical cost savings initiatives and the realignment of our MS&L operations and related consolidation and relocation of our corporate offices.

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

Our Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our consolidated financial statements and the accompanying footnotes.

This report, including information included or incorporated by reference herein, contains forward-looking statements concerning the financial condition, results of operations, plans, objectives, future performance and business of our company and its subsidiaries. These forward-looking statements include:

- statements that are not historical in nature, including, but not limited to: (i) our belief that anticipated cash from operations, cash distributions from entities that we control, and borrowing capacity under our credit facility will be sufficient to meet our anticipated liquidity needs for the foreseeable future; (ii) our belief that we do not have material potential liability in connection with legal proceedings that would have a significant financial impact on our consolidated financial condition, results of operations or cash flows; and (iii) our belief that our assets will continue to benefit from the development of unconventional shale plays as significant supply basins; and
- statements preceded by, followed by or that contain forward-looking terminology including the words "believe," "expect," "may," "will," "should," "could," "anticipate," "estimate," "intend" or the negation thereof, or similar expressions.

Forward-looking statements are not guarantees of future performance or results. They involve risks, uncertainties and assumptions. Actual results may differ materially from those contemplated by the forward-looking statements due to, among others, the following factors:

- our ability to successfully implement our business plan for our assets and operations;
- governmental legislation and regulations;
- industry factors that influence the supply of and demand for crude oil, natural gas and NGLs;
- industry factors that influence the demand for services in the markets (particularly unconventional shale plays) in which we provide services;
- weather conditions;
- the availability of crude oil, natural gas and NGLs, and the price of those commodities, to consumers relative to the price of alternative and competing fuels;
- economic conditions;
- costs or difficulties related to the integration of acquisitions and success of our joint ventures' operations;
- environmental claims;
- operating hazards and other risks incidental to the provision of midstream services, including gathering, compressing, treating, processing, fractionating, transporting and storing energy products (i.e., crude oil, NGLs and natural gas) and related products (i.e., produced water);
- interest rates;
- the price and availability of debt and equity financing, including our ability to raise capital through alternatives like joint ventures; and
- the ability to sell or monetize assets, to reduce indebtedness, to repurchase our equity securities, to make strategic investments, or for other general partnership purposes.

We have described under Part I, Item 1A. Risk Factors, additional factors that could cause actual results to be materially different from those described in the forward-looking statements. Other factors that we have not identified in this report could also have this effect.

Overview

We own and operate crude oil, natural gas and NGL midstream assets and operations. Headquartered in Houston, Texas, we are a fully-integrated midstream solution provider that specializes in connecting shale-based energy supplies to key demand markets. We conduct our operations through our wholly-owned subsidiary, Crestwood Midstream, a limited partnership that owns and operates gathering, processing, storage, and transportation assets in the most prolific shale plays across the United States.

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Our Company

We provide broad-ranging services to customers across the crude oil, natural gas and NGL sector of the energy value chain. Our midstream infrastructure is geographically located in or near significant supply basins, especially developed and emerging liquids-rich and crude oil shale plays, across the United States. We own or control:

- natural gas facilities with approximately 2.4 Bcf/d of gathering capacity and 0.5 Bcf/d of processing capacity;
- NGL facilities with approximately 20,000 Bbls/d of fractionation capacity and 3.1 MMBbls of storage capacity, as well as our portfolio of transportation assets (consisting of truck and rail terminals, truck/trailer units and rail cars) capable of transporting approximately 195,000 Bbls/d of NGLs; and
- crude oil facilities with approximately 125,000 Bbls/d of gathering capacity, 1.5 MMBbls of storage capacity, 20,000 Bbls/d of transportation capacity, and 160,000 Bbls/d of rail loading capacity.

In addition, through our equity investments in joint ventures, we have ownership interests in:

- natural gas facilities with approximately 0.3 Bcf/d of gathering capacity, 0.2 Bcf/d of processing capacity, 75.8 Bcf of certificated working storage capacity, and 1.5 Bcf/d of transportation capacity; and
- crude oil facilities with approximately 20,000 Bbls/d of rail loading capacity and 380,000 Bbls of working storage capacity.

Our financial statements reflect three operating and reporting segments: (i) gathering and processing, which includes our natural gas, crude oil and produced water G&P operations; (ii) storage and transportation, which includes our natural gas and crude oil storage and transportation operations; and (iii) marketing, supply and logistics, which includes our NGL supply and logistics business, crude oil storage and rail loading facilities and fleet.

Gathering and Processing

Our G&P operations and investments provide gathering, compression, treating, and processing services to producers in multiple unconventional resource plays across the United States and we have established footprints in “core of the core” areas of many of the largest shale plays. We believe that our strategy of focusing on prolific, low-cost shale plays positions us well to (i) generate greater returns in varying commodity price environments, (ii) capture greater upside economics when development activity occurs, and (iii) in general, better manage through commodity price cycles and production changes associated therewith.

Our G&P operations primarily include:

- Bakken. We own and operate an integrated crude oil, natural gas and produced water gathering system and processing facility (the Arrow system) in the core of the Bakken Shale in McKenzie and Dunn Counties, North Dakota, some of which is located on Fort Berthold Indian Reservation. The Arrow system consists of 640 miles of low-pressure gathering pipeline capable of gathering 100 MMcf/d of natural gas, 125 MBbls/d of crude oil, 40 MBbls/d of produced water, and the Bear Den processing plant includes approximately 30 MMcf/d of natural gas processing capacity. We also have approximately 266,000 Bbls of crude oil working storage capacity at the Arrow central delivery point;
- Marcellus. We own and operate natural gas gathering and compression systems in Harrison, Doddridge and Barbour Counties, West Virginia. These systems have a total gathering capacity of 875 MMcf/d and 131,380 horsepower of compression;
-

Barnett. We own and operate (i) a low-pressure natural gas gathering system with a gathering capacity of approximately 425 MMcf/d of rich gas produced by our customers in Hood and Somervell Counties, Texas, which delivers the rich gas to our processing plant where NGLs are extracted from the natural gas stream; and (ii) low-pressure gathering systems with a gathering capacity of 500 MMcf/d of dry natural gas produced by our customers in Tarrant and Denton Counties, Texas;

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- Fayetteville. We own and operate five low-pressure gas gathering systems with a gathering capacity of approximately 510 MMcf/d of dry natural gas produced by our customers in Conway, Faulkner, Van Buren, and White Counties, Arkansas;

- Granite Wash. We own and operate a low-pressure natural gas gathering system with a gathering capacity of approximately 36 MMcf/d of rich gas produced by our customers in Roberts County, Texas, and a processing plant that extracts NGLs from the natural gas stream;

- Delaware Permian. We own a 50% equity interest in the Crestwood Permian joint venture with an affiliate of First Reserve. We operate the joint venture, which owns low-pressure dry gas and rich natural gas gathering systems with a primary focus on the Willow Lake system, which includes approximately 75 MMcf/d of processing capacity that serves our customers in Eddy County, New Mexico. The joint venture also owns a 50% equity interest in Crestwood Permian Basin. In October 2017, Shell Midstream purchased a 50% equity interest in Crestwood Permian Basin. Crestwood Permian Basin owns and operates the Nautilus gathering system for SWEPI's gas production in an area of dedication (approximately 100,000 acres) in Loving, Reeves and Ward Counties, Texas. The initial build-out of the Nautilus gathering system was completed on June 6, 2017, and includes 20 receipt point meters, 60 miles of pipeline, a 24-mile high pressure header system, 10,800 horsepower of compression and a high pressure delivery point. The Nautilus gathering system is supported by a 20-year fixed-fee gathering agreement with SWEPI; and

- Powder River Basin. We own a 50% equity interest in the Jackalope joint venture with Williams. The joint venture, operated by Williams, owns the Jackalope gas gathering system and Bucking Horse processing plant. The Jackalope system is supported by a 10-year gathering and processing agreement with Chesapeake under an area of dedication of approximately 358,000 gross acres in the core of the Powder River Basin;

Although the cash flows from our G&P operations are predominantly fee-based under contracts with original terms ranging from 5-20 years, the results of our G&P operations are significantly influenced by the volumes gathered and processed through our systems. For example, due to market conditions that ultimately resulted in 2015 bankruptcy filings of two of our G&P customers (Quicksilver and Sabine), we gathered significantly lower volumes for those customers during 2015 and 2016 as they continued to shut-in wells during their respective bankruptcy proceedings. In April 2016, BlueStone bought Quicksilver's assets out of bankruptcy and thereafter returned to production wells that were previously shut-in by Quicksilver. We entered into new 10-year agreements with BlueStone to gather and process its production under fixed-fee and percent-of-proceeds fee structures, and pursuant to the agreements, BlueStone will not shut-in or choke back production for economic purposes through the end of 2018. As a result, the volumes we are now gathering and processing have returned to levels consistent with those preceding Quicksilver's bankruptcy filing. In March 2017, the Sabine bankruptcy proceedings were settled by the district court for the Southern District of New York, and the outcome was not material to our G&P segment's results of operations.

The cash flows from our G&P operations can also be impacted in the short term by changing commodity prices, seasonality and weather fluctuations. We gather, process, treat, compress, transport and sell crude oil and natural gas pursuant to a variety of contracts. These contracts include:

- Fixed-fee contracts. Under these contracts, we do not take title to the underlying crude, natural gas or NGLs but charge our customers a fixed-fee per volume gathered, processed, treated, compressed and/or transported. Certain of these agreements can contain commitments for a minimum level of volumes or revenues;

- Percentage-of-proceeds service contracts. Under these contracts, we effectively take title to crude, natural gas or NGLs after the commodity leaves our gathering and processing facilities. We often market and sell those commodities to third parties after they leave our facilities and we will remit a portion of the sales proceeds to our producers;

- Percentage-of-proceeds product contracts. Under these contracts, we effectively take title to crude, natural gas or NGLs before the commodity enters our gathering and processing facilities. We market and sell those commodities to third parties and we will remit a portion of the sales proceeds to our producers; and

- Purchase and sale contracts. Under these contracts, we purchase crude, natural gas or NGLs before the commodity enters our gathering and processing facilities, and we market and sell those commodities to third parties.

Our election to enter primarily into fixed-fee contracts minimizes our G&P segment’s commodity price exposure and provides us more stable operating performance and cash flows.

Storage and Transportation

Our S&T operations and investments consist of our crude oil terminals in the Bakken and Powder River Basin and our natural gas storage and transportation assets in the Northeast and Texas Gulf Coast, including:

- Bakken. We own and operate the COLT Hub, which is one of the largest crude oil rail terminals in the Bakken Shale based on actual throughput. Located approximately 60 miles from Arrow's central delivery point, the COLT Hub interconnects with the Arrow system through the Hiland and Andeavor pipeline systems. The COLT Hub, which can receive approximately 350,000 Bbls/d from interconnected gathering systems, is capable of loading up to 160,000 Bbls/d and storing approximately 1.2 MMBbls of crude oil. Moreover, because the COLT Hub and our Arrow system each interconnect with the DAPL interstate system, our Bakken crude oil assets are integrated and offer customers multiple service options since the DAPL interstate pipeline system was placed in service in 2017;

- Powder River Basin. PRBIC, our 50% equity method investment, owns an integrated crude oil loading, storage and pipeline terminal, located in Douglas County, Wyoming, which provides a market for crude oil production from the Powder River Basin. The joint venture, which is operated by our joint venture partner, Twin Eagle, sources crude oil production from Chesapeake and other Powder River Basin producers. PRBIC includes 20,000 Bbls/d of rail loading capacity and 380,000 Bbls of crude oil working storage capacity. The terminal connects to Kinder Morgan's Double H Pipeline system and Plains All American Pipeline's Rocky Mountain Pipeline system;

- Marcellus. Stagecoach Gas, our 50% equity method investment, owns four natural gas storage facilities (Stagecoach, Thomas Corners, Steuben and Seneca Lake) and three transportation pipelines (North/South Facilities, MARC I and the East Pipeline) located in or near the dry portion of the Marcellus Shale. The natural gas storage facilities provide 40.9 Bcf of certificated firm storage capacity and 1.5 Bcf/d of firm transportation capacity to producers, utilities, marketers and other customers. The location of these assets relative to New York City and other premium demand markets along the East Coast, together with the formation of our joint venture with a subsidiary of Consolidated Edison, helps to insulate our operations from production and commodity price changes that can impact storage and transportation operators in other geographic regions; and

- Texas Gulf Coast. Tres Holdings, our 50.01% equity method investment owns a FERC-certificated 34.9 Bcf multi-cycle, salt dome natural gas storage facility. The Tres Palacios storage facility's 63-mile, dual 24-inch diameter header system (including a 52-mile north pipeline lateral and an approximate 11-mile south pipeline lateral) interconnects with 11 pipeline systems and can receive residue gas from the tailgate of Kinder Morgan Inc.'s Houston central processing plant.

The cash flows from our S&T operations are predominantly fee-based under contracts with an original term ranging from 1-10 years. Our current cash flows from crude-by-rail facilities are supported by take-or-pay contracts with refiners and marketers. The rates and durations of the contracts associated with our crude oil terminals have eroded as pipelines come on-line that make crude-by-rail options less economical, which impacts our cash flows from operations. Cash flows from interruptible and other hub services provided by the natural gas storage facilities and pipelines owned by our joint ventures tends to increase during the peak winter season.

Marketing, Supply and Logistics

Our MS&L segment consists of our supply and logistics business, our storage and terminals business, our West Coast operations, and our crude oil, NGL and produced water trucking business. We utilize our over-the-road and rail fleet, processing and storage facilities, and contracted storage and pipeline capacity on a portfolio basis to provide integrated supply and logistics solutions to producers, refiners and other customers. In December 2017, we sold 100% of our equity interests in US Salt, a solution-mining and salt production company located on the shores of Seneca

Lake near Watkins Glen in Schuyler County, New York, to an affiliate of Kissner Group Holdings LP for net proceeds of approximately $223.6 million. As part of the US Salt divestiture, we retained all surface and sub-surface rights necessary to place the Watkins Glen NGL storage development project into service once we receive all required regulatory approvals.

Our MS&L operations primarily include:

- Supply and Logistics. Our Supply and Logistics operations are supported by i) our fleet of rail and rolling stock with 75,000 Bbls/d of NGL transportation capacity, which also includes our rail-to-truck terminals located in Florida, New Jersey, New York, Rhode Island and North Carolina; and ii) NGL pipeline and storage capacity leased from third

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parties, including more than 500,000 Bbls of NGL working storage capacity at major hubs in Mt. Belvieu, Texas and Conway, Kansas;

- Storage and Terminals. Our NGL Storage and Terminals operations include our Seymour and Bath storage facilities, which are supported by third-party pipelines and/or rail and truck terminal facilities;

- West Coast. Our West Coast NGL operations provide processing, fractionation, storage, transportation and marketing services to producers, refiners and other customers. We separate NGLs from natural gas, deliver to local natural gas pipelines, retain NGLs for further processing at our fractionation facility, provide butane isomerization and refrigerated storage services, as well as provide to Western US refineries for motor fuel production. Our operations also consists of wholesale propane assets primarily including three rail-to-truck terminals located in Hazen, Nevada, Carlin, Nevada, and Shoshoni, Wyoming and a truck terminal located in Salt Lake City, Utah. These terminals are used to provide supply, transportation and storage services to wholesale customers in the western and north central regions of the United States; and

- Trucking. Our Trucking operations consist of a fleet of owned and leased trucks with 20,000 Bbls/d of crude oil and produced water transportation capacity and 120,000 Bbls/d of NGL transportation capacity. We provide hauling services to customers in North Dakota, Montana, Wyoming, Texas, New Mexico, Indiana, Mississippi, New Jersey, Ohio, Utah and California.

The cash flows from our marketing, supply and logistics business represent sales to creditworthy customers typically under contracts with durations of one year or less, and tend to be seasonal in nature due to customer profiles and their tendencies to purchase NGLs during peak winter periods.

Outlook and Trends

Our business objective is to create long-term value for our unitholders. We expect to create long-term value by consistently generating stable operating margins and improved cash flows from operations by prudently financing our investments, maximizing throughput on our assets, and effectively controlling our operating and administrative costs. Our business strategy depends, in part, on our ability to provide increased services to our customers at competitive fees, including opportunities to expand our services resulting from expansions, organic growth projects and acquisitions that can be financed appropriately.

Through the challenging market environment from 2014 through 2017, we have taken a number of strategic steps to better position the Company as a stronger, better capitalized company that can over time accretively grow cash flows and sustainably resume growing our distributions. Those strategic steps included (i) simplifying our corporate structure to eliminate our incentive distribution rights (IDRs) and create better alignment of interests with our unitholders; (ii) divesting assets to reduce approximately $1 billion of long-term debt to ensure long-term balance sheet strength; (iii) realigning our operating structure to significantly reduce operating and administrative expenses; (iv) forming strategic joint ventures to enhance our competitive position around certain operating assets; and (v) focusing our growth capital expenditures on our highest return organic projects around our core growth assets in the Bakken Shale and Delaware Permian. We will remain focused on efficiently allocating capital expenditures by investing in accretive, organic growth projects, maintaining low-cost operations (through increased operating efficiencies and cost discipline) and maintaining our balance sheet strength through continued financial discipline. We expect to focus on expansion and greenfield opportunities in the Bakken Shale and Delaware Permian in the near term, while closely monitoring longer-term expansion opportunities in the Powder River Basin and northeast Marcellus. As a result, the Company is well positioned to execute its business plan and capitalize on the improving market conditions around many of our core assets.

While market conditions remain challenging around some of our assets, the Company continues to be positioned to generate consistent results in a low commodity price environment without sacrificing revenue upside as market conditions improve. For example, many of our more mature G&P assets are supported by long-term, core acreage dedications in shale plays that are economic to varying degrees based upon natural gas, NGL and crude oil prices, the availability of infrastructure to flow production to market, and the operational and financial condition of our diverse customer base. In addition, a substantial portion of our midstream investments are based on fixed-fee, take-or-pay or minimum volume commitment agreements that ensure a minimum level of cash flow regardless of actual commodity prices or volumetric throughput. Over time, we expect cash flows from our more mature, non-core, assets to stabilize and potentially increase with the improving commodity price environment, while the growth from our core assets in the Bakken Shale, Delaware Permian, Powder River Basin and northeast Marcellus drive significant growth to the Company.

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Below is a discussion of events that highlight our core business and financing activities. Through continued execution of our plan, we have materially improved the strategic and financial position of the Company and expect to capitalize on increasing opportunities in an improving but competitive market environment, which will position us to achieve our chief business objective to create long-term value for our unitholders.

Gathering and Processing

Bakken. In the Bakken, we are expanding and upgrading our Arrow system water handling facilities and increasing natural gas capacity on the system, which should allow for substantial growth in volumetric throughput across all of our crude oil, produced water and natural gas gathering systems. We are completing construction of a 30 MMcf/d natural gas processing facility and associated pipelines that began receiving gas in late 2017. In addition, we are constructing a 120 MMcf/d cryogenic plant that is designed to fulfill 100% of the processing requirements for producers on the Arrow system upon expiration of third-party processing contracts in the third quarter 2019. We expect to invest approximately $195 million on the expansion with a targeted in-service date in the second quarter 2019. Upon completion of the expansion, we expect to have a combined 150 MMcf/d of gas processing capacity in the Bakken. We believe the installation of a gas processing solution on the Arrow system will, among other things, spur greater development activity around the Arrow system, allow us to provide greater flow assurance to our producer customers and reduce flaring of natural gas, and reduce the downstream constraints currently experienced by producers on the Fort Berthold Indian Reservation.

Delaware Permian. In the Delaware Permian, we have identified gathering and processing and transportation opportunities in and around our existing assets, including our joint ventures. Through our Crestwood Permian joint venture, we are expanding our gathering and processing capacity in the region, which includes the construction of a 200 MMcf/d natural gas processing facility in Orla, Texas, and associated pipelines, as well as our interconnection capacity to accommodate greater takeaway options for residue gas and NGLs. The initial cost of the expansion project is expected to cost approximately $170 million with an in-service date in the second half of 2018. We are also evaluating expansion opportunities to provide midstream services for crude oil and produced water, including crude gathering, crude oil and condensate storage and terminalling, condensate stabilization, truck loading/unloading options and connections to third party pipelines and produced water gathering, disposal and recycling.

On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico, our wholly-owned subsidiary that owns our Delaware Basin assets located in Eddy County, New Mexico. This contribution was treated as a transaction between entities under common control, and accordingly we deconsolidated Crestwood New Mexico and our investment in Crestwood Permian was increased by the historical book value of these assets of approximately $69.4 million. In conjunction with this contribution, First Reserve has agreed to contribute to Crestwood Permian the first $151 million of capital costs required to fund the expansion of the Delaware Basin assets, which includes the Orla processing plant and associated pipelines. In October 2017, CPB Subsidiary Holdings LLC, a wholly-subsidiary of Crestwood Permian, entered into a credit agreement with certain lenders. The five year term credit agreement allows for revolving loans, letters of credit and swingline loans in an aggregate principal amount of up to $150 million. Borrowings under the credit agreement will be used to fund expansion projects and for general corporate purposes.

Crestwood Permian Basin has a long-term agreement with SWEPI to construct, own and operate a natural gas gathering system in SWEPI's operated position in the Delaware Permian. SWEPI has dedicated to Crestwood Permian Basin approximately 100,000 acres and gathering rights for SWEPI's gas production across a large acreage position in Loving, Reeves, Ward and Culberson Counties, Texas. The Nautilus gathering system will be constructed to ultimately include 194 miles of low pressure gathering lines, 36 miles of high pressure trunklines and centralized compression facilities which are expandable over time as production increases, producing gas gathering capacity of approximately 250 MMcf/d. In addition, the Orla processing plant described above, will be further expanded and integrated to connect the Nautilus gas gathering system to the Orla plant. The initial build-out of the Nautilus gathering system was completed on June 6, 2017, and includes 20 receipt point meters, 60 miles of pipeline, a 24-mile high pressure header system, 10,800 horsepower of compression and a high pressure delivery point. Crestwood Permian Basin provides gathering, dehydration, compression and liquids handling services to SWEPI under a 20-year fixed-fee gathering agreement. In October 2017, Shell Midstream purchased a 50% equity interest in Crestwood Permian Basin for approximately $37.9 million in cash.

Marketing, Supply and Logistics

Our MS&L operations own NGL storage and terminalling assets in the Northeast U.S. and our West Coast processing facility. During 2017, we experienced NGL market headwinds in the Northeast, with our NGL exports and other market dynamics causing price differentials to narrow between purchasing NGLs in the summer (which are stored in our NGL facilities) and selling NGLs in the winter. These dynamics also caused the rates that we were able to charge for storing NGLs in our facilities to decline from their historical levels. Also during 2017, our West Coast customers also experienced headwinds, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S. This caused demand for the gathering, processing and logistics services from our West Coast operations to remain relatively flat in 2017 compared to 2016.

In December 2017, we sold 100% of our equity interests in US Salt, a solution-mining and salt production company located on the shores of Seneca Lake near Watkins Glen in Schuyler County, New York, to an affiliate of Kissner Group Holdings LP for net proceeds of approximately $223.6 million.

Regulatory Matters

Many aspects of the energy midstream sector, such as crude-by-rail activities and pipeline integrity, have experienced increased regulatory oversight over the past few years. However, under the current Presidential Administration, we anticipate changes in policy that could lessen the degree of regulatory scrutiny we face in the near term.

In December 2017, the Tax Cuts and Jobs Act (the Tax Act) was passed by the U.S. Congress, which modified several aspects of the U.S. income tax code beginning in 2018. We are currently evaluating how many of these modifications will impact master limited partnerships such as CEQP and its unitholders. In particular, we are evaluating the impact that the Tax Act will have on our unitholders' ability to deduct business interest from their taxable income, since the Tax Act requires that the business interest deduction be limited to the sum of business interest income and 30% of adjusted taxable income. For the purposes of this limitation, adjusted taxable income will be computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Critical Accounting Estimates and Policies

Our significant accounting policies are described in Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

The preparation of financial statements in conformity with GAAP requires management to select appropriate accounting estimates and to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those that require difficult, complex, or subjective judgment necessary in accounting for inherently uncertain matters and those that could significantly influence our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. We have discussed the development and selection of the following critical accounting estimates and related disclosures with the Audit Committee of the board of directors of our general partner.

Goodwill Impairment

Our goodwill represents the excess of the amount we paid for a business over the fair value of the net identifiable assets acquired. We evaluate goodwill for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount. This evaluation requires us to compare the fair value of each of our reporting units to its carrying value (including goodwill). If the fair value exceeds the carrying amount, goodwill of the reporting unit is not considered impaired.

We estimate the fair value of our reporting units based on a number of factors, including discount rates, projected cash flows and the potential value we would receive if we sold the reporting unit. We also compare the total fair value of our reporting units to our overall enterprise value, which considers the market value for our common and preferred units. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our reporting units (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates. If the assumptions embodied in the projections prove inaccurate, we could incur a future impairment charge. In addition, the use of the income approach to determine the fair value of our reporting units (see further discussion of the income approach below) could result in a different fair value if we had utilized a market approach, or a combination thereof.

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We acquired substantially all of our reporting units in 2013, 2012 and 2011, which required us to record the assets, liabilities and goodwill of each of those reporting units at fair value on the date they were acquired. As a result, any level of decrease in the forecasted cash flows of these businesses or increases in the discount rates utilized to value those businesses from their respective acquisition dates would likely result in the fair value of the reporting unit falling below the carrying value of the reporting unit, and could result in an assessment of whether that reporting unit's goodwill is impaired.

Current commodity prices are significantly lower compared to commodity prices during 2014, and that decrease has adversely impacted forecasted cash flows, discount rates and stock/unit prices for most companies in the midstream industry, including us. In light of these circumstances, we evaluated the carrying value of our reporting units and determined it was more likely than not that the goodwill associated with several of our reporting units was impaired and as a result, we recorded goodwill impairments on several of our reporting units during 2017, 2016 and 2015 as shown in the table below (in millions). During 2017, we adopted the provision of ASU 2017-04, Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment, which allows companies to apply a single test to determine if goodwill is impaired and the amount of any impairment, which is reflected in our 2017 goodwill impairments.

	Goodwill Impairments during the Year Ended December 31, 2015	Goodwill Impairments during the Year Ended December 31, 2016	Goodwill Impairments during the Year Ended December 31, 2017	Goodwill at December 31, 2017
G&P				
Fayetteville	$ 72.5	$ —	$ —	$ —
Marcellus	—	8.6	—	—
Arrow	—	—	—	45.9
S&T				
COLT	623.4	44.9	—	—
MS&L				
West Coast	85.9	—	2.4	—
Supply and Logistics	99.0	65.5	—	101.7
Storage and Terminals	53.7	14.1	36.4	—
Trucking	148.4	29.5	—	—
Watkins Glen	66.2	—	—	—
Total Crestwood Midstream	$ 1,149.1	$ 162.6	$ 38.8	$ 147.6
Barnett (G&P)	257.2	—	—	—
Total Crestwood Equity	$ 1,406.3	$ 162.6	$ 38.8	$ 147.6

The goodwill impairments recorded during 2017 related to our MS&L West Coast and Storage and Terminals operations. The goodwill impairment related to our MS&L West Coast operations resulted from decreasing forecasted cash flows to be generated by those operations. Our West Coast customers experienced headwinds during 2017, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S., which caused demand for gathering, processing and logistics services from our West Coast operations to remain relatively flat over the past several years. Although our West Coast operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the degree that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future. The goodwill impairment related to our MS&L Storage and Terminals operations resulted from decreasing forecasted cash flows to be generated by those operations. During 2017, we experienced NGL market headwinds in the Northeast with NGL exports and other market dynamics causing price differentials to narrow between purchasing NGLs in the summer (which are then stored in our NGL facilities) and selling NGLs in the winter. These dynamics also caused the rates that we are able to charge for storing NGLs in our facilities to decline from their historical levels. Although our MS&L Storage and Terminals operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the decrease that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future. We utilized the income approach to determine the fair value of our reporting units given the limited availability of comparable market-based transactions during 2017, and we utilized discount rates ranging from 10% to 12% in applying the income approach to determine the fair value of our reporting units with goodwill as of December 31, 2017, which is a Level 3 fair value measurement.

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As a result of these analyses and impairments, we only have two reporting units with goodwill associated with them at December 31, 2017 (Arrow and Supply and Logistics). We continue to monitor our remaining goodwill, and we could experience additional impairments of the remaining goodwill in the future if we experience a significant sustained decrease in the market value of our common or preferred units or if we receive additional negative information about market conditions or the intent of our customers on our remaining operations with goodwill, which could negatively impact the forecasted cash flows or discount rates utilized to determine the fair value of those businesses. In particular, a 5% decrease in the forecasted cash flows or a 1% increase in the discount rates utilized to determine the fair value of our business would not have resulted in goodwill impairments at our two remaining reporting units with goodwill associated with them.

Long-Lived Assets

Our long-lived assets consist of property, plant and equipment and intangible assets that have been obtained through multiple historical business combinations and property, plant and equipment that has been constructed in recent years. The initial recording of a majority of these long-lived assets was at fair value, which is estimated by management primarily utilizing market-related information and other projections on the performance of the assets acquired. Management reviews this information to determine its reasonableness in comparison to the assumptions utilized in determining the purchase price of the assets in addition to other market-based information that was received through the purchase process and other sources. These projections also include projections on potential and contractual obligations assumed in these acquisitions. Due to the imprecise nature of the projections and assumptions utilized in determining fair value, actual results can, and often do, differ from our estimates.

We utilize assumptions related to the useful lives and related salvage value of our property, plant and equipment in order to determine depreciation and amortization expense each period. Due to the imprecise nature of the projections and assumptions utilized in determining useful lives, actual results can, and often do, differ from our estimates.

To estimate the useful life of our finite lived intangible assets we utilize assumptions of the period over which the assets are expected to contribute directly or indirectly to our future cash flows. Generally this requires us to amortize our intangible assets based on the expected future cash flows (to the extent they are readily determinable) or on a straight-line basis (if they are not readily determinable) of the acquired contracts or customer relationships. Due to the imprecise nature of the projections and assumptions utilized determining future cash flows, actual results can, and often do, differ from our estimates.
We continually monitor our business, the business environment and the performance of our operations to determine if an event has occurred that indicates that a long-lived asset may be impaired. If an event occurs, which is a determination that involves judgment, we may be required to utilize cash flow projections to assess our ability to recover the carrying value of our assets based on our long-lived assets' ability to generate future cash flows on an undiscounted basis. This differs from our evaluation of goodwill, for which we perform an assessment of the recoverability of goodwill utilizing fair value estimates that primarily utilize discounted cash flows in the estimation process (as described above), and accordingly a reporting unit that has experienced a goodwill impairment may not experience a similar impairment of the underlying long-lived assets included in that reporting unit. During 2017, 2016 and 2015, we recorded the following impairments of our intangible assets and property, plant and equipment:

- During 2017, we incurred $82.2 million of impairments of our property, plant and equipment and intangible assets related to our MS&L West Coast operations, which resulted from decreasing forecasted cash flows to be generated by those operations. Our West Coast customers experienced headwinds during 2017, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S., which caused demand for the gathering, processing and logistics services from our West Coast operations to remain relatively flat in 2017 compared to 2016. Although our West Coast operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the degree that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future.

- During 2016, we incurred a $31.4 million impairment of intangible assets related to our MS&L Trucking operations, which resulted from the impact of increased competition on our Trucking business and the loss of several key customer relationships that were acquired in 2013 to which the intangible assets related.

- During 2015, we incurred $8.5 million of impairments of our property, plant and equipment related to our Granite Wash gathering and processing operations, which resulted from decreases in forecasted cash flows for those operations given that our major customer of those assets has declared bankruptcy and has ceased any substantial drilling in the

Granite Wash in the near future given current and future anticipated market conditions related to natural gas and NGLs.

- During 2015, we incurred $593.3 million of impairments of our intangible assets and property, plant and equipment related to our Barnett gathering and processing operations, which resulted from the recent actions of our primary customer in the Barnett Shale, Quicksilver, related to its filing for protection under Chapter 11 of the U.S. Bankruptcy Code in 2015.

- During 2015, we incurred $184.5 million of impairments of our intangible assets and property, plant and equipment related to our Fayetteville and Haynesville gathering and processing operations, which resulted from decreases in forecasted cash flows for those operations given that our customers for those assets have ceased any substantial drilling in the Fayetteville and Haynesville Shales in the near future given current and future anticipated market conditions related to natural gas.

- During 2015, we incurred $31.2 million of impairments of our property, plant and equipment related to our Watkins Glen marketing, supply and logistics segment development project, which resulted from continued delays and uncertainties in the permitting of our proposed NGL storage facility.

Projected cash flows of our long-lived assets are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, construction costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. If those cash flow projections indicate that the long-lived asset's carrying value is not recoverable, we record an impairment charge for the excess of carrying value of the asset over its fair value. The estimate of fair value considers a number of factors, including the potential value we would receive if we sold the asset, discount rates and projected cash flows. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

We continue to monitor our long-lived assets, and we could experience additional impairments of the remaining carrying value of these long-lived assets in the future if we receive additional negative information about market conditions or the intent of our long-lived assets' customers, which could negatively impact the forecasted cash flows or discount rates utilized to determine the fair value of those investments.

Equity Method Investments

We evaluate our equity method investments for impairment when events or circumstances indicate that the carrying value of the equity method investment may be impaired and that impairment is other than temporary. If an event occurs, we evaluate the recoverability of our carrying value based on the fair value of the investment. If an impairment is indicated, we adjust the carrying values of the asset downward, if necessary, to their estimated fair values.

We estimate the fair value of our equity method investments based on a number of factors, including discount rates, projected cash flows, enterprise value and the potential value we would receive if we sold the equity method investment. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our equity method investments (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our equity method investments' customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

Because our Jackalope and PRBIC equity method investments were acquired in 2013, any level of decrease in the forecasted cash flows of these investments or increases in the discount rates utilized to value those investments from their respective acquisition dates would likely result in the fair value of the equity method investment falling below their carrying value, and could result in an assessment of whether that investment is impaired.

During 2015, we recorded a $51.4 million and $23.4 million impairment of our Jackalope and PRBIC equity method investments, respectively, as a result of decreasing forecasted cash flows and increasing the discount rate utilized in determining the fair value of the equity method investment considering the continued decrease in commodity prices and its impact on the midstream industry and our equity method investments' customers.

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We continue to monitor our equity method investments, and we could experience additional impairments of the remaining carrying value of these investments in the future if we receive additional negative information about market conditions or the intent of our equity method investments' customers, which could negatively impact the forecasted cash flows or discount rates utilized to determine the fair value of those investments.

Variable Interest Entities

We evaluate all legal entities in which we hold an ownership interest to determine if the entity is a variable interest entity (VIE). Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership or other interests in an entity that change with changes in the fair value of the VIE's assets. When we conclude that we hold an interest in a VIE we must determine if we are the entity's primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE.

We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated. Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE. We use primarily a qualitative analysis to determine if an entity is a VIE. We evaluate the entity's need for continuing financial support; the equity holder's lack of a controlling financial interest; and/or if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns. We evaluate our interests in a VIE to determine whether we are the primary beneficiary. We use primarily a qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE, either on a standalone basis or as part of a related party group. We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions. As a result of this analysis, we concluded that our investment in Crestwood Permian is a VIE that we are not the primary beneficiary of, and as a result, we account for our investment in Crestwood Permian as an equity method investment.

Our other equity investments are not considered to be VIEs. However, any future changes in the design or nature of the activities of these entities may require us to reconsider our conclusions associated with these entities. Such reconsideration would require the identification of the variable interests in the entity and a determination on which party is the entity's primary beneficiary. If an equity investment were considered a VIE and we were determined to be the primary beneficiary, the change could cause us to consolidate the entity. The consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for more information on our equity method investments.

How We Evaluate Our Operations

We evaluate our overall business performance based primarily on EBITDA and Adjusted EBITDA. We do not utilize depreciation, amortization and accretion expense in our key measures because we focus our performance management on cash flow generation and our assets have long useful lives.

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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. We believe that EBITDA and Adjusted EBITDA are useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. EBITDA is defined as income before income taxes, plus debt-related costs (interest and debt expense, net, and gain (loss) on modification/extinguishment of debt) and depreciation, amortization and accretion expense. Adjusted EBITDA considers the adjusted earnings impact of our unconsolidated affiliates by adjusting our equity earnings or losses from our unconsolidated affiliates to reflect our proportionate share (based on the distribution percentage) of their EBITDA, excluding impairments. Adjusted EBITDA also considers the impact of certain significant items, such as unit-based compensation charges, gains and losses on long-lived assets, impairments of long-lived assets and goodwill, third party costs incurred related to potential and completed acquisitions, certain environmental remediation costs, certain costs related to our historical cost saving initiatives, the change in fair value of commodity inventory-related derivative contracts, costs associated with our 2017 realignment of our Marketing, Supply and Logistics operations and related consolidation and relocation of our corporate offices, and other transactions identified in a specific reporting period. The change in fair value of commodity inventory-related derivative contracts is considered in determining Adjusted EBITDA given that the timing of recognizing gains and losses on these derivative contracts differs from the recognition of revenue for the related underlying sale of inventory to which these derivatives relate. Changes in the fair value of other derivative contracts is not considered in determining Adjusted EBITDA given the relatively short-term nature of those derivative contracts. 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 as alternatives 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.

See our reconciliation of net income to EBITDA and Adjusted EBITDA in Results of Operations below.

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Results of Operations

The following table summarizes our results of operations (in millions).

	Crestwood Equity			Crestwood Midstream	
	Year Ended December 31,			Year Ended December 31,	
	2017	2016	2015	2017	2016
Revenues	$3,880.9	$2,520.5	$2,632.8	$3,880.9	$2,520.5
Costs of product/services sold	3,374.7	1,925.1	1,883.5	3,374.7	1,925.1
Operations and maintenance	136.0	158.1	190.2	136.0	155.0
General and administrative	96.5	88.2	116.3	93.1	85.6
Depreciation, amortization and accretion	191.7	229.6	300.1	202.7	240.5
Loss on long-lived assets, net	(65.6)	(65.6)	(821.2)	(65.6)	(65.6)
Goodwill impairment	(38.8)	(162.6)	(1,406.3)	(38.8)	(162.6)
Loss on contingent consideration	(57.0)	—	—	(57.0)	—
Operating loss	(79.4)	(108.7)	(2,084.8)	(87.0)	(113.9)
Earnings (loss) from unconsolidated affiliates, net	47.8	31.5	(60.8)	47.8	31.5
Interest and debt expense, net	(99.4)	(125.1)	(140.1)	(99.4)	(125.1)
Gain (loss) on modification/extinguishment of debt	(37.7)	10.0	(20.0)	(37.7)	10.0
Other income, net	1.3	0.5	0.6	0.8	—
(Provision) benefit for income taxes	0.8	(0.3)	1.4	—	—
Net loss	(166.6)	(192.1)	(2,303.7)	(175.5)	(197.5)
Add:					
Interest and debt expense, net	99.4	125.1	140.1	99.4	125.1
(Gain) loss on modification/extinguishment of debt	37.7	(10.0)	20.0	37.7	(10.0)
Provision (benefit) for income taxes	(0.8)	0.3	(1.4)	—	—
Depreciation, amortization and accretion	191.7	229.6	300.1	202.7	240.5
EBITDA	161.4	152.9	(1,844.9)	164.3	158.1
Unit-based compensation charges	25.5	19.2	19.7	25.5	19.2
Loss on long-lived assets, net	65.6	65.6	821.2	65.6	65.6
Goodwill impairment	38.8	162.6	1,406.3	38.8	162.6
Loss on contingent consideration	57.0	—	—	57.0	—
(Earnings) loss from unconsolidated affiliates, net	(47.8)	(31.5)	60.8	(47.8)	(31.5)
Adjusted EBITDA from unconsolidated affiliates, net	80.3	61.1	25.3	80.3	61.1
Change in fair value of commodity inventory-related derivative contracts	2.2	14.1	5.4	2.2	14.1
Significant transaction and environmental-related costs and other items[(1)]	12.4	11.6	33.6	12.4	11.6
Adjusted EBITDA	$395.4	$455.6	$527.4	$398.3	$460.8

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	Crestwood Equity			Crestwood Midstream	
	Year Ended December 31,			Year Ended December 31,	
	2017	2016	2015	2017	2016
EBITDA:					
Net cash provided by operating activities	$255.9	$346.1	$440.7	$262.2	$353.8
Net changes in operating assets and liabilities	(0.3)	(57.9)	(98.0)	(2.4)	(56.8)
Amortization of debt-related deferred costs, discounts and premiums	(7.2)	(6.9)	(8.9)	(7.2)	(6.9)
Interest and debt expense, net	99.4	125.1	140.1	99.4	125.1
Market adjustment on interest rate swaps	—	—	0.5	—	—
Unit-based compensation charges	(25.5)	(19.2)	(19.7)	(25.5)	(19.2)
Loss on long-lived assets, net	(65.6)	(65.6)	(821.2)	(65.6)	(65.6)
Goodwill impairment	(38.8)	(162.6)	(1,406.3)	(38.8)	(162.6)
Loss on contingent consideration	(57.0)	—	—	(57.0)	—
Earnings (loss) from unconsolidated affiliates, net, adjusted for cash distributions received	0.1	(7.6)	(73.6)	0.1	(7.6)
Deferred income taxes	2.1	3.1	3.6	—	(0.2)
Provision (benefit) for income taxes	(0.8)	0.3	(1.4)	—	—
Other non-cash expense	(0.9)	(1.9)	(0.7)	(0.9)	(1.9)
EBITDA	161.4	152.9	(1,844.9)	164.3	158.1
Unit-based compensation charges	25.5	19.2	19.7	25.5	19.2
Loss on long-lived assets, net	65.6	65.6	821.2	65.6	65.6
Goodwill impairment	38.8	162.6	1,406.3	38.8	162.6
Loss on contingent consideration	57.0	—	—	57.0	—
(Earnings) loss from unconsolidated affiliates, net	(47.8)	(31.5)	60.8	(47.8)	(31.5)
Adjusted EBITDA from unconsolidated affiliates, net	80.3	61.1	25.3	80.3	61.1
Change in fair value of commodity inventory-related derivative contracts	2.2	14.1	5.4	2.2	14.1
Significant transaction and environmental-related costs and other items[1]	12.4	11.6	33.6	12.4	11.6
Adjusted EBITDA	$395.4	$455.6	$527.4	$398.3	$460.8

(1) Significant transaction and environmental-related costs and other items for the years ended December 31, 2017, 2016 and 2015, primarily include costs incurred related to the Simplification Merger and other merger, acquisition and joint venture transactions, as well as costs associated with our historical cost savings initiatives and the realignment of our MS&L operations and related consolidation and relocation of our corporate offices.

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Segment Results

The following tables summarize the EBITDA of our segments (in millions):

Crestwood Equity	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics
Revenues	$ 1,688.2	$ 37.2	$ 2,155.5
Intersegment revenues	134.5	6.7	(141.2)
Costs of product/services sold	1,480.8	0.3	1,893.6
Operations and maintenance expenses	68.4	4.2	63.4
Loss on long-lived assets, net	(14.4)	—	(48.2)
Goodwill impairments	—	—	(38.8)
Loss on contingent consideration	—	(57.0)	—
Earnings from unconsolidated affiliates, net	18.9	28.9	—
Other income, net	0.8	—	—
EBITDA for the year ended December 31, 2017	$ 278.8	$ 11.3	$ (29.7)
Revenues	$ 1,118.8	$ 165.3	$ 1,236.4
Intersegment revenues	108.6	4.2	(112.8)
Costs of product/services sold	917.0	5.1	1,003.0
Operations and maintenance expenses	77.0	21.4	59.7
Loss on long-lived assets, net	(2.0)	(32.2)	(31.4)
Goodwill impairments	(8.6)	(44.9)	(109.1)
Earnings from unconsolidated affiliates, net	20.3	11.2	—
EBITDA for the year ended December 31, 2016	$ 243.1	$ 77.1	$ (79.6)
Revenues	$ 1,381.0	$ 266.3	$ 985.5
Intersegment revenues	66.7	—	(66.7)
Costs of product/services sold	1,103.9	20.1	759.5
Operations and maintenance expenses	89.0	31.7	69.5
Loss on long-lived assets, net	(787.3)	(1.6)	(32.3)
Goodwill impairments	(329.7)	(623.4)	(453.2)
Loss from unconsolidated affiliates, net	(43.4)	(17.4)	—
EBITDA for the year ended December 31, 2015	$ (905.6)	$ (427.9)	$ (395.7)

Crestwood Midstream			
Revenues	$ 1,688.2	$ 37.2	$ 2,155.5
Intersegment revenues	134.5	6.7	(141.2)
Costs of product/services sold	1,480.8	0.3	1,893.6
Operations and maintenance expenses	68.4	4.2	63.4
Loss on long-lived assets net	(14.4)	—	(48.2)
Goodwill impairments	—	—	(38.8)
Loss on contingent consideration	—	(57.0)	—
Earnings from unconsolidated affiliates, net	18.9	28.9	—
Other income, net	0.8	—	—
EBITDA for the year ended December 31, 2017	$ 278.8	$ 11.3	$ (29.7)
Revenues	$ 1,118.8	$ 165.3	$ 1,236.4
Intersegment revenues	108.6	4.2	(112.8)
Costs of product/services sold	917.0	5.1	1,003.0

Operations and maintenance expenses	77.0	18.3	59.7
Loss on long-lived assets, net	(2.0)	(32.2)	(31.4)
Goodwill impairments	(8.6)	(44.9)	(109.1)
Earnings from unconsolidated affiliates, net	20.3	11.2	—
EBITDA for the year ended December 31, 2016	$243.1	$80.2	$(79.6)

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Segment Results

Below is a discussion of the factors that impacted EBITDA by segment for the years ended December 31, 2017, 2016 and 2015.

Gathering and Processing

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

EBITDA for CEQP's and CMLP's gathering and processing segment increased by approximately $35.7 million for the year ended December 31, 2017 compared to 2016. During the year ended December 31, 2017, our gathering and processing segment's revenues increased by approximately $595.3 million compared to 2017, partially offset by an increase in costs of product/services sold of approximately $563.8 million during 2017 compared to 2016.

The increases in revenues and costs during the year ended December 31, 2017 were primarily driven by our Arrow operations, which experienced a $611.0 million increase in revenues and a $578.5 million increase in costs of product/services compared to 2016. The increase in Arrow's revenues and costs was primarily driven by higher average prices on Arrow's agreements under which it purchases and sells crude oil. In addition, crude, gas and water volumes gathered by our Arrow system increased by 30%, 10% and 27%, respectively, during the year ended December 31, 2017 compared to 2016, due to the connection of 97 wells on our Arrow system during 2017 compared to 48 wells during 2016.

Partially offsetting the increase in our gathering and processing segment's revenues and costs from our Arrow operations during the year ended December 31, 2017 compared to 2016, were lower revenues and costs of approximately $16.4 million and $10.6 million, respectively, from our Permian operations as a result of the deconsolidation of Crestwood New Mexico in June 2017. For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6.

Our gathering and processing segment's operations and maintenance expenses decreased by approximately $8.6 million during the year ended December 31, 2017 compared to 2016, due to continued cost-reduction efforts undertaken in our operations and the deconsolidation of Crestwood New Mexico.

Our gathering and processing segment's EBITDA for the year ended December 31, 2017 includes a loss on long-lived assets of approximately $14.4 million, primarily related to the retirement and/or disposition of certain of our Marcellus and Arrow gathering and processing assets.

The comparability of our G&P segment's EBITDA was impacted by an $8.6 million impairment recorded during the year ended December 31, 2016 related to our Marcellus operations. For a further discussion of these impairments, see "Critical Accounting Estimates and Policies" above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Our gathering and processing segment's EBITDA was also impacted by a decrease in earnings from unconsolidated affiliates of approximately $1.4 million during the year ended December 31, 2017 compared to 2016. The decrease was primarily driven by a $10.3 million decrease in equity earnings from Jackalope resulting from a reduction in revenues at the equity investment as a result of the restructuring of its contracts with Chesapeake effective January 1, 2017. Jackalope and Chesapeake replaced the cost-of-service based contract with a fixed-fee gathering and processing contract that includes minimum revenue guarantees for a five to seven year period. Partially offsetting the decrease in equity earnings from Jackalope was an increase in equity earnings from our Crestwood Permian equity investment of approximately $8.9 million during the year ended December 31, 2017 compared 2016, primarily due to the contribution of Crestwood New Mexico to Crestwood Permian in June 2017, and the Nautilus system coming online in June 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

EBITDA for CEQP's G&P segment increased by approximately $1,148.7 million for the year ended December 31, 2016 compared to 2015. The comparability of our G&P's segment results year-over-year was significantly impacted by property, plant and equipment, intangible asset and goodwill impairments recorded during 2016 and 2015, which are further described below.

During the year ended December 31, 2016, our G&P segment's revenues were lower by approximately $220.3 million compared to 2015, partially offset by lower costs of product/services sold of approximately $186.9 million. These decreases were primarily driven by our Arrow operations, which experienced a $193.9 million reduction in revenues during the year ended December 31, 2016 compared to 2015, offset by a $194.0 million decrease in costs of product/services sold. These

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decreases in Arrow's revenues and costs were driven by lower market prices on crude oil, which caused average prices on Arrow's agreements under which it purchases and sells crude to decrease. Gathering volumes on the Arrow system were relatively flat in 2016 compared to 2015.

Also contributing to the decrease in our G&P segment's revenues were lower service revenues from our Marcellus and Barnett operations of approximately $20.7 million and $14.8 million, respectively, during the year ended December 31, 2016 compared to 2015. During the year ended December 31, 2016, we experienced a decrease in our gathering and compression volumes on our Marcellus system due to lack of drilling from our primary customer, Antero, as a result of the decline in commodity prices. Our gathering and compression volumes were 0.4 Bcf/d and 0.5 Bcf/d, respectively during the year ended December 31, 2016 compared to 0.5 Bcf/d and 0.6 Bcf/d during 2015. Our Barnett operations experienced a decrease in service revenues during 2016 compared to 2015 as a result of our primary customer, Quicksilver, ceasing drilling and shutting in production during the first quarter of 2016 as a result of its filing for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. In April 2016, BlueStone bought Quicksilver's assets out of bankruptcy and thereafter returned to production wells that were previously shut-in by Quicksilver. We entered into new 10-year gathering and processing agreements with BlueStone and pursuant to those agreements, BlueStone will not shut-in or choke back production for economic purposes through the end of 2018. As a result, gathering and processing volumes on our Barnett system have returned to levels relatively consistent with those preceding Quicksilver's bankruptcy filing.

Partially offsetting the decreases from our Arrow, Marcellus and Barnett operations discussed above, were lower operations and maintenance expenses of $12.0 million during the year ended December 31, 2016 compared to 2015, primarily as a result of our cost reduction initiatives implemented in 2015.

Our G&P segment's EBITDA was also impacted by a goodwill impairment of $8.6 million recorded during 2016 related to our Marcellus operations compared to property, plant and equipment, intangible asset and goodwill impairments of approximately $1,116.0 million recorded during 2015 related to our Barnett, Fayetteville, Granite Wash, and Haynesville operations. For a further discussion of these impairments, see "Critical Accounting Estimates and Policies" above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Our G&P segment's EBITDA was impacted by an increase in net earnings from unconsolidated affiliates of approximately $63.7 million. During the year ended December 31, 2016, earnings from our Jackalope equity investment increased by $64.2 million primarily due to a $51.4 million impairment recorded on the investment in 2015 and higher gathering and processing volumes at the facility resulting from Jackalope placing the Bucking Horse processing plant into service in 2015.

Storage and Transportation

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

EBITDA for CMLP's storage and transportation segment decreased by approximately $68.9 million during the year ended December 31, 2017 compared to 2016. During the year ended December 31, 2017, our storage and transportation segment's revenues were lower due to a reduction in revenues of approximately $51.1 million from our COLT Hub operations compared to 2016. The decrease was primarily due to a reduction in our rail throughput revenues from the expiration of two rail loading contracts in late 2016, a 58% decrease in rail loading volumes and lower margins resulting from higher average crude oil prices in the Bakken compared to other basins, which has decreased the demand and rates for our rail loading services in 2017 compared to 2016. Also impacting our storage and transportation segment's EBITDA was $44.9 million of goodwill impairments recorded during the year ended December 31, 2016 related to our COLT Hub operations. For a further discussion of these impairments, see "Critical Accounting Estimates and Policies" above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

The comparability of our storage and transportation segment's EBITDA was also impacted by a $57 million loss on contingent consideration recorded during the year ended December 31, 2017 related to our Stagecoach Gas joint venture. Pursuant to the Stagecoach Gas limited liability company agreement, we may be required to make payments of up to $57 million to CEGP after December 31, 2020 if certain criteria are not met by Stagecoach Gas by December 31, 2020, including achieving certain performance targets on growth capital projects. These growth capital projects depend on the construction of other third-party expansion projects, and during 2017, those third-party projects experienced regulatory and other delays that caused Stagecoach Gas to delay its growth capital projects. Although Stagecoach Gas anticipates that these growth capital projects will be constructed in the future, it does not expect that these projects will produce meaningful operating results prior to December 31, 2020.

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Our storage and transportation segment's results was impacted by a $32.4 million loss recognized on the deconsolidation of our Northeast storage and transportation assets as a result of the contribution of these assets to the Stagecoach Gas joint venture in June 2016. The deconsolidation of the Northeast storage and transportation assets resulted in lower revenues and costs of product/services sold of approximately $74.5 million and $4.6 million, respectively, during the year ended December 31, 2017 compared to 2016. We also experienced lower operations and maintenance expenses of approximately $14.1 million during the year ended December 31, 2017 compared to 2016, primarily as a result of the deconsolidation of the Northeast storage and transportation assets. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Notes 2 and 6 for a further discussion of the deconsolidation of our NE S&T assets.

Our storage and transportation segment's EBITDA was impacted by an increase in earnings from our unconsolidated affiliates. As discussed above, in June 2016, we deconsolidated our Northeast storage and transportation assets as a result of the Stagecoach Gas transaction and began accounting for our 50% equity interest in Stagecoach Gas under the equity method of accounting. We recognized equity earnings from Stagecoach Gas of approximately $25.3 million and $15.9 million during the years ended December 31, 2017 and 2016. Earnings from our Tres Holdings equity investment increased by approximately $2.5 million during the year ended December 31, 2017 compared to 2016, primarily due to property tax accruals recorded by Tres Holdings during 2016.

EBITDA for CEQP's storage and transportation segment decreased by approximately $65.8 million during the year ended December 31, 2017 compared to 2016. The change in CEQP's storage and transportation segment's EBITDA year-over-year was due to all the factors discussed above for CMLP. In addition, in June 2016, the Matagorda County court issued a final judgment related to Tres Palacios' 2012 and 2013 property tax years which resulted in CEQP recording additional net property taxes (including interest and penalties) of approximately $2.9 million during the year ended December 31, 2016.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

EBITDA for CEQP's storage and transportation segment increased by approximately $505.0 million during the year ended December 31, 2016 compared to 2015. The comparability of our storage and transportation segment's results year-over-year is primarily impacted by goodwill impairments recorded during 2016 and 2015, which are further described below. In addition, on June 3, 2016, we deconsolidated our NE S&T assets as a result of the contribution of the assets to Stagecoach Gas and we recognized a loss of $32.4 million. The deconsolidation of the NE S&T assets also resulted in lower revenues of approximately $102.3 million during the year ended December 31, 2016 compared to the 2015, partially offset by lower costs of product/services sold of approximately $8.7 million year-over-year. We also experienced lower operations and maintenance expense of approximately $11.9 million during the year ended December 31, 2016 compared to 2015, primarily as a result of the deconsolidation of the NE S&T assets. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Notes 2 and 6 for a further discussion of the deconsolidation of our NE S&T assets.

Our COLT Hub operations experienced an increase in revenues of approximately $5.4 million during the year ended December 31, 2016 compared to 2015, primarily due to the recognition in income of previously deferred revenues related to two rail loading contracts that expired in late 2016, which was partially offset by a related reduction in our actual rail throughput revenues resulting from lower rail loading volumes primarily under those contracts. Our lower rail loading volumes were a result of narrowed crude oil locational differences in the Bakken, and were partially offset by a related decrease in costs of product/services sold of $6.3 million during the year ended December 31, 2016 compared to 2015.

Our storage and transportation segment's EBITDA was also impacted by goodwill impairments related to our COLT Hub operations of approximately $44.9 million and $623.4 million during the years ended December 31, 2016 and

2015. For a further discussion of our goodwill impairments recorded during 2016 and 2015, see “Critical Accounting Estimates and Policies” above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

In June 2016, the Matagorda County court issued a final judgment related to Tres Palacios’ 2012 and 2013 property tax years which resulted in Crestwood Equity recording additional net property taxes (including interest and penalties) of approximately $2.9 million during the year ended December 31, 2016.

Our storage and transportation segment’s EBITDA was impacted by a $28.6 million increase in earnings from unconsolidated affiliates. As discussed above, effective June 3, 2016, we deconsolidated the NE S&T assets as a result of the Stagecoach Gas transaction and began accounting for our 50% equity interest in Stagecoach Gas under the equity method of accounting. We recognized equity earnings from Stagecoach Gas of approximately $15.9 million during the year ended December 31, 2016. Our equity earnings from Tres Holdings were lower by approximately $2.8 million during the year ended December 31, 2016 compared to the same period in 2015, primarily due to an increase in property tax accruals at the equity investment. Our equity earnings from our PRBIC equity investment increased by $15.5 million, primarily due to an impairment of $23.4 million of the

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investment recorded in 2015, partially offset by a $4.4 million loss from the investment in 2016 driven by an impairment recorded at the equity investee level due to declining actual and forecasted revenues from its major customer, Chesapeake.

Marketing, Supply and Logistics

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

EBITDA for our marketing, supply and logistics segment increased by approximately $49.9 million for the year ended December 31, 2017 compared to 2016. The comparability of our marketing, supply and logistics segment's results was significantly impacted by goodwill, intangible assets and property, plant and equipment impairments of $121.0 million recorded during 2017 and goodwill and intangible asset impairments of $140.5 million recorded during 2016. For a further discussion of our impairments recorded during 2017 and 2016, see "Critical Accounting Estimates and Policies" above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Our supply and logistics operations experienced an increase in revenues and costs of product/services sold of $465.0 million and $457.9 million, respectively, during the year ended December 31, 2017 compared to 2016. During 2016, we experienced unseasonably warm weather which resulted in lower demand for NGLs compared to increased demand experienced during 2017. The costs of product/services sold increase includes losses of $31.2 million and a loss of $7.8 million during the years ended December 31, 2017 and 2016 related to our commodity-based derivative contracts. These changes in the fair value of our derivative contracts resulted from higher average NGL prices compared to 2016, which resulted in an increase in our liabilities from price risk management activities associated with contracts that provide fixed prices on future sales of our NGL inventory.

During the year ended December 31, 2017, our storage and terminals operations (including our West Coast operations) experienced a $173.6 million and $174.4 million increase in revenues and costs of product/services sold, respectively, compared to 2016. These increases were primarily driven by increases in NGL prices during the year ended December 31, 2017. Although our net operating results were relatively consistent during the year ended December 31, 2017 compared to 2016, we experienced NGL market headwinds in the Northeast during 2017, with NGL exports and other market dynamics causing price differentials to narrow between purchasing NGLs in the summer (which are then stored in our NGL facilities) and selling NGLs in the winter. These dynamics also caused the rates that we are able to charge for storing NGLs in our facilities to decline from their historical levels. Also during 2017, our West Coast customers also experienced headwinds, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S. This caused demand for the gathering, processing and logistics services from our West Coast operations to remain relatively flat in 2017 compared to 2016. Considering the fact that the net operating results of our storage and terminals operations (including West Coast) have been relatively consistent over the past several years, we do not anticipate that these operations will grow as fast or to the degree that we expected when we merged with Inergy, LP in 2013 given current market dynamics, which we believe will continue for the foreseeable future.

Revenues and costs of product/services sold from our crude and natural gas marketing operations increased by approximately $261.9 million and $260.5 million, respectively, during the year ended December 31, 2017 compared to 2016. These increases were primarily driven by higher crude marketing volumes due to increased marketing activity surrounding our crude-related operations.

Our NGL and crude trucking operations continued to experience lower operating results in 2017 compared to 2016, with a $12.4 million and $5.7 million decrease in revenues and costs of product/services sold during the year ended December 31, 2017 compared to 2016. This decrease was primarily a result of the realignment of our trucking operations in 2017 to reduce the size of our trucking fleet in response to the continued decline in demand for trucking services due to the continued lower commodity price environment.

Our marketing, supply and logistic segment’s operations and maintenance expenses increased by approximately $3.7 million during the year ended December 31, 2017 compared to 2016. In 2016, we received a $3.1 million property tax refund related to our West Coast operations.

In December 2017, we sold 100% of our equity interests in US Salt to an affiliate of Kissner Group Holdings LP for net proceeds of approximately $223.6 million, and we recognized a gain of approximately $33.6 million from the sale. For a further discussion of this sale, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3.

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Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

EBITDA for our marketing, supply and logistics segment increased by approximately $316.1 million during the year ended December 31, 2016 compared to 2015. The comparability of our marketing, supply and logistics segment's results year over year is impacted by goodwill impairments recorded during 2016 and 2015, which are further described below.

Our NGL and crude trucking operations experienced a continued decrease in the demand for their services due to lower volumes, increased competition, excess trucking capacity in the market place and the low commodity price environment during the year ended December 31, 2016, resulting in a 18% and 65% decrease in NGL and crude volumes transported, respectively, compared to 2015. This resulted in a $34.6 million decrease in revenues during the year ended December 31, 2016 compared to 2015, and a $21.8 million decrease in costs of services sold from these operations during the same period.

During the year ended December 31, 2016, our storage and terminals operations (including our West Coast operations) experienced a $147.7 million increase in revenues compared to 2015, in addition to an increase in costs of product/services sold of approximately $167.6 million. Although these operations experienced an increase in demand for its propane-related services year-over-year, it experienced lower demand for its butane-related services (which tend to generate higher per unit margins than its propane services). The lower butane demand was driven by lower NGL commodity prices and tightening of basis differentials on these operations in 2016 compared to 2015.

Our supply and logistics operations experienced a decrease in revenues of approximately $58.0 million and a decrease in costs of product/services sold of $51.0 million during the year ended December 31, 2016 compared to 2015. These decreases were due to the low commodity price environment coupled with warmer weather during 2016 compared to 2015, which resulted in lower demand for the butane-related services provided by these operations. These revenues and costs of services decreases include a loss of $7.8 million on our commodity-based derivative contracts of during the year ended December 31, 2016 and a gain of $18.9 million during the year ended December 31, 2015.

During the year ended December 31, 2016, revenues from our crude marketing operations increased by approximately $146.8 million compared to 2015, in addition to an increase of approximately $147.6 million in our costs of product/services sold year-over-year, both of which were driven by higher crude marketing volumes due to increased marketing activity surrounding our crude-related operations during 2016.

Our marketing, supply and logistics segment's operations and maintenance expense decreased by $9.8 million during the year ended December 31, 2016 compared to 2015, primarily due to our cost-savings initiative implemented in 2015.

Our marketing, supply and logistics segment's EBITDA for the year ended December 31, 2016 was also impacted by intangible asset and goodwill impairments of approximately $140.5 million related to our supply and logistics, storage and terminals and trucking operations compared to property, plant and equipment and goodwill impairments of $484.4 million related to our West Coast, supply and logistics, storage and terminals, trucking and Watkins Glen operations in 2015. For a further discussion of our impairments recorded during 2016 and 2015, see "Critical Accounting Estimates" above and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Other EBITDA Results

General and Administrative Expenses.

During the year ended December 31, 2017, our general and administrative expenses increased compared to 2016, primarily due to an increase in unit-based compensation charges based on higher average awards outstanding in 2017 compared to 2016, and the impact of performance units granted during 2017 under the Crestwood Equity Long Term Incentive Plan (Crestwood LTIP). For a further discussion of Crestwood LTIP, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 13. In addition, we incurred additional expense during the year ended December 31, 2017, related to the consolidation and relocation of our three corporate offices into two offices located in Houston and Kansas City.

During 2015, we completed a number of cost-reduction efforts, including the Simplification Merger (see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2 for a discussion of the Simplification Merger), and as a result we decreased our ongoing operations and maintenance expense and general and administrative expense. During the year ended December 31, 2016 compared to 2015, we experienced a decrease of approximately $28.1 million in Crestwood Equity's general and administrative expenses primarily as a result of our cost-savings initiatives.

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Items not affecting EBITDA include the following:

Depreciation, Amortization and Accretion Expense. During the year ended December 31, 2017, our depreciation, amortization and accretion expense decreased compared to 2016 and 2015, primarily due to the deconsolidation of our Crestwood New Mexico operations in June 2017, the deconsolidation of our NE S&T assets in June 2016, and a reduction in the carrying value of certain of our assets as a result of impairments on our property, plant and equipment and intangible assets recorded during 2015.

Interest and Debt Expense, Net. During the year ended December 31, 2017, interest and debt expense, net decreased compared to 2016 and 2015, primarily due to the repayments of Crestwood Midstream's 2020 Senior Notes and 2022 Senior Notes. For a discussion of our long-term debt and related transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9.

The following table provides a summary of our interest and debt expense (in millions).

	CEQP Year Ended December 31,			CMLP Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
Credit facilities	$18.6	$18.7	$25.2	$18.6	$18.7	$17.2
Senior notes	76.4	99.9	108.4	76.4	99.9	107.8
Other debt-related costs	7.3	7.2	9.0	7.3	7.2	8.0
Gross interest and debt expense	102.3	125.8	142.6	102.3	125.8	133.0
Less: capitalized interest	2.9	0.7	2.5	2.9	0.7	2.5
Interest and debt expense, net	$99.4	$125.1	$140.1	$99.4	$125.1	$130.5

Gain (Loss) on Modification/Extinguishment of Debt. During the year ended December 31, 2017, we recognized a loss on extinguishment of debt of approximately $37.7 million in conjunction with the tender of the remaining principal amounts of
Crestwood Midstream's 2020 Senior Notes and 2022 Senior Notes. During the year ended December 31, 2016, we recognized a gain on extinguishment of debt of approximately $10.0 million in conjunction with the early tender of a portion of Crestwood Midstream's 2020 Senior Notes and 2022 Senior Notes.

During the year ended December 31, 2015, we recognized a $20.0 million loss on extinguishment of debt related to the termination of Crestwood Equity's credit facility, the redemption of Crestwood Midstream's 2019 Senior Notes and modification of Crestwood Midstream's credit facility.

Net Income (Loss) Attributable to Non-Controlling Partners. In September 2015, Crestwood Midstream became a wholly-owned subsidiary of Crestwood Equity as a result of the Simplification Merger, which materially impacted the change in Crestwood Equity's net income (loss) attributable to non-controlling partners for the year ended December 31, 2016 compared to 2015. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 12 for further detail of Crestwood Equity's net income (loss) attributable to non-controlling partners.

Liquidity and Sources of Capital

Crestwood Equity is a holding company that derives all of its operating cash flow from its operating subsidiaries. Our principal sources of liquidity include cash generated by operating activities from our subsidiaries, distributions from our joint ventures, borrowings under the CMLP credit facility, and sales of equity and debt securities. Our operating subsidiaries use cash from their respective operations to fund their operating activities, maintenance and growth capital expenditures, and service their outstanding indebtedness. We believe our liquidity sources and operating cash flows are sufficient to address our future operating, debt service and capital requirements.

We make cash quarterly distributions to our common unitholders within approximately 45 days after the end of each fiscal quarter in an aggregate amount equal to our available cash for such quarter. We also pay cash quarterly distributions of approximately $15 million to our preferred unitholders. We believe our operating cash flows will well exceed cash distributions to our partners and our preferred unitholders at current levels, and as a result, we will have substantial operating cash flows as a source of liquidity for our growth capital expenditures.

In December 2017, we sold 100% of our equity interests in US Salt, a solution-mining and salt production company located on the shores of Seneca Lake near Watkins Glen in Schuyler County, New York, to an affiliate of Kissner Group Holdings LP for

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net proceeds of approximately $223.6 million. We used the proceeds from the divestiture to reduce borrowings under the CMLP credit facility and reinvest in on-going organic growth projects in the Bakken and Delaware Basin discussed in Outlook and Trends above, and we expect the proceeds from this divestiture will eliminate the need to access the equity capital markets to fund our current capital programs.

As of December 31, 2017, we had $499.3 million of available capacity under our credit facility considering the most restrictive debt covenants in the credit agreement. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions, tender offers or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. As of December 31, 2017, we were in compliance with all of our debt covenants applicable to the credit facility and our senior notes. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9 for a more detailed description of the credit facility and senior notes.

The following table provides a summary of Crestwood Equity's cash flows by category (in millions):

	Year Ended December 31,		
	2017	2016	2015
Net cash provided by operating activities	$255.9	$346.1	$440.7
Net cash provided by (used in) investing activities	38.7	867.2	(212.7)
Net cash used in financing activities	(294.9)	(1,212.2)	(236.3)

Operating Activities

Our operating cash flows decreased approximately $90.2 million for the year ended December 31, 2017 compared to 2016, primarily due to a $125.6 million decrease in our storage and transportation segment's revenues primarily due to the deconsolidation of our Northeast storage and transportation assets and a reduction in rail throughput revenues from our COLT operations. This was partially offset by a $1,488.5 million increase in revenues from our gathering and processing and marketing, supply and logistics operations discussed above, offset by a $1,449.6 million increase in costs of product/services sold primarily related to these segments' operations.
Our operating cash flows decreased approximately $94.6 million for the year ended December 31, 2016 compared to 2015, primarily due to a $112.3 million decrease in operating revenues as a result of the deconsolidation of the NE S&T assets in June 2016 and from our gathering and processing segment's operations due primarily to the effect of lower commodity prices on that segment. The unfavorable cash flow impacts were partially offset by lower operations and maintenance expenses of approximately $32.1 million, primarily due to the deconsolidation of the NE S&T assets.

Investing Activities

The energy midstream business is capital intensive, requiring significant investments for the acquisition or development of new facilities. We categorize our capital expenditures as either:

- growth capital expenditures, which are made to construct additional assets, expand and upgrade existing systems, or acquire additional assets; or

- maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets, extend their useful lives or comply with regulatory requirements.

During 2018, we anticipate growth capital expenditures of approximately $250 million to $300 million, which includes contributions to our equity investments related to their capital projects. In addition, we expect to spend between approximately $15 million to $20 million on maintenance capital expenditures and approximately $25 million to $30 million on capital expenditures that are directly reimbursable by our customers. We anticipate that our growth and reimbursable capital expenditures in 2018 will increase the services we can provide to our customers and the operating efficiencies of our systems. We expect to finance our capital expenditures with a combination of cash generated by our operating subsidiaries, distributions received from our equity investments and borrowings under our credit facility.

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We have identified additional growth capital project opportunities for each of our reporting segments. Additional commitments or expenditures will be made at our discretion, and any discontinuation of the construction of these projects will likely result in less future cash flow and earnings. The following table summarizes our capital expenditures for the year ended December 31, 2017 (in millions).

Growth capital	$ 141.4
Maintenance capital	22.0
Other[(1)]	25.0
Purchases of property, plant and equipment	188.4
Reimbursements of property, plant and equipment	(19.6)
Net	$ 168.8

(1) Represents gross purchases of property, plant and equipment that are reimbursable by third parties.

In addition to the capital expenditures described in the table above, our cash flows from investing activities were also impacted by the following significant items during the years ended December 31, 2017, 2016 and 2015:

Net Proceeds from the Sale of Assets. In December 2017, we sold 100% of our equity interests in US Salt to an affiliate of Kissner Group Holdings LP for net proceeds of approximately $223.6 million. In June 2016, we contributed to Stagecoach Gas the entities owning the NE S&T assets, CEGP contributed $975 million in exchange for a 50% equity interest in Stagecoach Gas, and Stagecoach Gas distributed to us the net cash proceeds received from CEGP. For a further discussion of these transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Notes 2, 3 and 6.

Investments in Unconsolidated Affiliates. During the years ended December 31, 2017, 2016 and 2015, we made cash contributions of approximately $58 million, $12.4 million and $42 million, respectively, to our joint ventures to fund their growth capital projects and their operating activities. In addition, in June 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico at our historical book value of approximately $69.4 million. This contribution was treated as a non-cash transaction between entities under common control.

Distributions from our joint ventures increased during each of the three years ended December 31, 2017, primarily due to the formation of the Crestwood Permian and Stagecoach joint ventures in October 2016 and June 2016, respectively. In addition, we experienced an increase in distributions from our Jackalope equity investment during the year ended December 31, 2016 compared to 2015, as a result of Jackalope placing an expansion project into service in 2015.

Financing Activities

Significant items impacting our financing activities during the years ended December 31, 2017, 2016 and 2015 included the following:

Equity Transactions

- In December 2017, Crestwood Niobrara redeemed 100% of the outstanding preferred units issued to a subsidiary of General Electric Capital Corporation and GE Structured Finance, Inc. (collectively, GE) for an aggregate purchase price of $202.7 million and issued $175 million of new preferred units to CN Jackalope Holdings LLC. For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 12;
- Distributions to preferred unitholders of approximately $15 million; prior to September 30, 2017, we had the option to make quarterly distributions to our preferred unitholders by issuing additional preferred units;
-

- Decrease in distributions to partners of approximately $52.2 million during the year ended December 31, 2017 compared to 2016, primarily due to a reduction in distributions paid per limited partner unit from $1.375 to $0.60 beginning with the first quarter 2016 distribution; increase in distributions to partners of approximately $48.3 million for the year ended December 31, 2016 compared to 2015, primarily due to the increase in the number of limited partner units outstanding as a result of the Simplification Merger;
- Decrease in distributions paid to non-controlling partners of $219 million in 2016 compared to 2015, due primarily to the Simplification Merger; distributions paid to non-controlling partners during the year ended December 31, 2017 were flat compared to 2016;

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- $15.2 million of net proceeds from the issuance of CEQP common units during the year ended December 31, 2017; and
- Increase in taxes paid for unit-based compensation vesting of approximately $4.7 million, primarily due to higher vesting of unit-based compensation awards during the year ended December 31, 2017 compared to 2016.

Debt Transactions

During the year ended December 31, 2017, our debt-related transactions resulted in net repayments of approximately $76.3 million compared to net repayments of $974.5 million in 2016 and net proceeds of $131.5 million in 2015.

- During 2017 and 2016, we redeemed all amounts outstanding under Crestwood Midstream's 2020 Senior Notes and 2022 Senior Notes. During 2017 and 2015, we issued $500 million of senior unsecured notes due in 2025 and $700 million senior unsecured notes due in 2023, respectively. For a further discussion of these and other debt-related transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9.

Contractual Obligations

We are party to various contractual obligations. A portion of these obligations are reflected in our financial statements, such as long-term debt and other accrued liabilities, while other obligations, such as operating leases, capital commitments and contractual interest amounts are not reflected on our balance sheet. The following table and discussion summarizes our contractual cash obligations as of December 31, 2017 (in millions):

	Less than 1 Year	1-3 Years	3-5 Years	Thereafter	Total
Long-term debt:					
Principal	$0.9	$319.3	$0.4	$ 1,200.0	$1,520.6
Interest(1)	85.9	162.9	145.0	75.6	469.4
Future minimum payments under operating leases(2)	35.2	53.3	19.2	18.8	126.5
Asset retirement obligations	—	—	—	27.5	27.5
Fixed price commodity purchase commitments(3)	447.3	32.0	—	—	479.3
Standby letters of credit	52.2	—	—	—	52.2
Purchase commitments and other contractual obligations(4)	65.8	—	—	—	65.8
Total contractual obligations	$687.3	$567.5	$164.6	$ 1,321.9	$2,741.3

(1) $318.2 million of our long-term debt is variable interest rate debt at Alternate Base rate or Eurodollar rate plus an applicable spread. These rates plus their applicable spreads were between 3.94% and 6.00% at December 31, 2017. These rates have been applied for each period presented in the table.

(2) See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 15 for a further discussion of these obligations.

(3) Fixed price purchase commitments are volumetrically offset by third party fixed price sale contracts.

(4) Primarily related to growth and maintenance contractual purchase obligations in our G&P segment and environmental obligations included in other current liabilities on our balance sheet. Other contractual purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations.

Off-Balance Sheet Arrangements

As of December 31, 2017, we have not entered into any transactions, agreements or other arrangements that would result in off-balance sheet liabilities.

Our equity interest in Crestwood Permian is considered to be a variable interest entity. We are not the primary beneficiary of Crestwood Permian and as a result, we account for our investment in Crestwood Permian as an equity method investment. For a further discussion of our investment in Crestwood Permian, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in the interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows.

As of December 31, 2017, both the carrying value and fair value of our fixed rate debt instruments was approximately $1.2 billion. As of December 31, 2016, both the carrying value and fair value of our fixed rate debt instruments (including debt fair value adjustments) was approximately $1.5 billion. For a further discussion of our fixed rate debt, see Part IV, Item 15. Exhibits and Financial Statement Schedules, Note 9.

We are subject to the risk of loss associated with changes in interest rates on our credit facility. At December 31, 2017, we had obligations totaling $318.2 million outstanding under the credit facility. These obligations expose us to the risk of increased interest payments in the event of increases in short-term interest rates. Floating rate obligations expose us to the risk of increased interest expense in the event of increases in short-term interest rates. If the interest rate on the our credit facility were to fluctuate by 1% from the rate as of December 31, 2017, our annual interest expense would have changed by approximately $3.2 million.

Commodity Price, Market and Credit Risk

Inherent in our business are certain business risks, including market risk and credit risk.

Market Risk

We typically do not take title to the natural gas, NGLs or crude oil that we gather, store, or transport for our customers. However, we do take title to (i) the NGLs and crude oil marketed or supplied by our NGL and crude oil supply and logistics operations (marketing, supply and logistics segment); (ii) NGLs under certain of our percent-of-proceeds contracts (G&P segment); and (iii) crude oil and natural gas purchased from our Arrow and Granite Wash producer customers (G&P segment). Our current business model is designed to minimize our exposure to fluctuations in commodity prices, although we are willing to assume commodity price risk in certain processing and marketing activities. We remain subject to volumetric risk under contracts without minimal volume commitments or take-or-pay pricing terms, but absent other market factors that could adversely impact our operations (i.e., market conditions that negatively influence our producer customers' decisions to develop or produce hydrocarbons), changes in the price of natural gas, NGLs or crude oil should not materially impact our operations.

In our marketing, supply and logistics operations, we consider market risk to be the risk that the value of our NGL and crude services segment's portfolio will change, either favorably or unfavorably, in response to changing market conditions. We take an active role in managing and controlling market risk and have established control procedures, which are reviewed on an ongoing basis. We monitor market risk through a variety of techniques, including daily reporting of the portfolio's position to senior management. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with assets from price risk management activities as of December 31, 2017, were energy marketers, propane retailers, resellers, and dealers.

We engage in hedging and risk management transactions, including various types of forward contracts, options, swaps and futures contracts, to reduce the effect of price volatility on our product costs, protect the value of our inventory positions and to help ensure the availability of propane during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes only when we have a matching purchase commitment from our marketing customers. However, we may experience net unbalanced positions from time to time, which we believe to be immaterial in amount. In addition to our ongoing policy to maintain a balanced position, for accounting purposes we are required, on an ongoing basis, to track and report the market value of our derivative portfolio. These derivatives are not designated as hedges for accounting purposes.

The fair value of the derivatives contracts related to price risk management activities as of December 31, 2017 were assets of $7.2 million and liabilities of $48.9 million. We use observable market values for determining the fair value of our trading instruments. In cases where actively quoted prices are not available, other external sources are used that incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis. Our risk management department regularly compares valuations to independent sources and models on a quarterly basis. A theoretical change of 10% in the underlying commodity value would result in a $8.6 million change in the market value of these contracts as there were approximately 2 MMBbls of net unbalanced positions at December 31, 2017. Inventory positions of approximately 2 MMBbls would substantially offset this theoretical change at December 31, 2017.

Credit Risk

Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing and controlling credit risk and have established control procedures, which are reviewed on an ongoing basis. We have diversified our credit risk through having long-term contracts with many investment grade customers and creditworthy producers. Additionally, we perform credit analyses of our customers on a regular basis pursuant to our corporate credit policy. We have not had any significant losses due to failures to perform by our counterparties.

Under a number of our customer contracts, there are provisions that provide for our right to request or demand credit assurances from our customers including the posting of letters of credit, surety bonds, cash margin or collateral held in escrow for varying levels of future revenues. We continue to closely monitor our producer customer base since a majority of our customers in our consolidated gathering and processing and storage and transportation operations are either not rated by the major rating agencies or had below investment grade credit ratings.

Item 8. Financial Statements and Supplementary Data

Reference is made to the financial statements and report of independent registered public accounting firm included later in this report under Part IV, Item 15. Exhibits, Financial Statement Schedules.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As of December 31, 2017, Crestwood Equity and Crestwood Midstream carried out an evaluation under the supervision and with the participation of their respective management, including the Chief Executive Officers and Chief Financial Officers of their General Partners, as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in the Securities Exchange Act of 1934, as amended (Exchange Act) Rules 13a-15(e) and 15d-15(e)). Crestwood Equity and Crestwood Midstream maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in their respective reports that are filed or submitted under the Exchange Act of 1934, as amended, are recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC, and that information is accumulated and communicated to their respective management, including the Chief Executive Officers and Chief Financial Officers of their General Partners, as appropriate, to allow timely decisions regarding required disclosure. Such management, including the Chief Executive Officers and Chief Financial Officers of their General Partners, does not expect that the disclosure controls and procedures or the internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Crestwood Equity's and Crestwood Midstream's disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and the Chief Executive Officers and Chief Financial Officers of their General Partners concluded that such disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2017.

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Changes in Internal Control over Financial Reporting

There have been no changes in Crestwood Equity's or Crestwood Midstream's internal control over financial reporting during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect Crestwood Equity's and Crestwood Midstream's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Crestwood Equity's and Crestwood Midstream's management is responsible for establishing and maintaining adequate internal control over financial reporting, pursuant to Exchange Act Rules 13a-15(f). Crestwood Equity's and Crestwood Midstream's internal control systems were designed to provide reasonable assurance to their respective management and board of directors regarding the preparation and fair presentation of published financial statements in accordance with GAAP.

Management recognizes that there are inherent limitations in the effectiveness of any system of internal control, and accordingly, even effective internal control can provide only reasonable assurance with respect to financial statement preparation and fair presentation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Under the supervision and with the participation of Crestwood Equity's and Crestwood Midstream's management, including the Chief Executive Officers and Chief Financial Officers, Crestwood Equity and Crestwood Midstream assessed the effectiveness of their respective internal control over financial reporting as of December 31, 2017. In making this assessment, Crestwood Equity and Crestwood Midstream used the criteria set forth in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based upon such assessment, Crestwood Equity and Crestwood Midstream concluded that, as of December 31, 2017, their respective internal control over financial reporting is effective, based upon those criteria.

Crestwood Equity's independent registered public accounting firm, Ernst & Young LLP, issued an attestation report dated February 23, 2018, on the effectiveness of our internal control over financial reporting, which is included herein.

Item 9B. Other Information

On February22, 2018, Crestwood Operations entered into an Omnibus Amendment to each Executive Employment Agreement for Messrs. Phillips, Halpin, Moore, Dougherty and Lambert ("Omnibus Amendment"). Pursuant to the Omnibus Amendment, if, on or before July 1, 2019, there is a Change in Control (as defined in the Omnibus Amendment), the Partnership will issue 150,000 restricted units to Mr. Phillips, 100,000 restricted units to Mr. Halpin, and 75,000 restricted units to Messrs. Moore, Dougherty and Lambert, respectively, which units will be fully vested on their issuance date. Furthermore, if the employment of Messrs. Halpin, Moore, Dougherty or Lambert is terminated during the period beginning three months prior to a Change in Control and ending twelve months after a Change in Control, then the severance amount payable shall be increased to three (3) times base salary and average annual bonus for the prior two years.

The foregoing summary of the material provisions of the Omnibus Amendment is intended to be general in nature and is qualified by the full text of the Omnibus Amendment, which is incorporated by reference herein as an exhibit to the Annual Report on Form 10-K.

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PART III

Item 10, "Directors, Executive Officers and Corporate Governance;" Item 11, "Executive Compensation;" Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters;" and Item 13, "Certain Relationships and Related Transactions, and Director Independence" have been omitted from this report for Crestwood Midstream pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Item 10. Directors, Executive Officers and Corporate Governance

Our General Partner Manages Crestwood Equity Partners LP

Crestwood Equity GP LLC, our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 $^2/_3$% of the outstanding units, including units held by the general partner and their affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of the general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units. Unitholders do not directly or indirectly participate in our management or operations. Our general partner owes a fiduciary duty to the unitholders. Our general partner is liable, as a general partner, for all of our debts (to the extent not paid from our assets), except for specific nonrecourse indebtedness or other obligations. Whenever possible, our general partner intends to incur indebtedness or other obligations that are nonrecourse.

As is commonly the case with publicly-traded limited partnerships, we are managed and operated by the officers of our general partner and are subject to the oversight of the directors of our general partner. The board of directors of our general partner is presently composed of seven directors.

Directors and Executive Officers

The following table sets forth certain information with respect to the executive officers and members of the board of directors of our general partner. Executive officers and directors will serve until their successors are duly appointed or elected.

Executive Officers and Directors	Age	Position with our General Partner
Robert G. Phillips	63	President, Chief Executive Officer and Director
J. Heath Deneke	44	Executive Vice President, Chief Operating Officer
Robert T. Halpin	34	Executive Vice President, Chief Financial Officer
Steven M. Dougherty	45	Senior Vice President, Chief Accounting Officer
Joel C. Lambert	49	Senior Vice President, General Counsel and Chief Compliance Officer
William H. Moore	38	Senior Vice President, Strategy and Corporate Development
Alvin Bledsoe	69	Director
Michael G. France	40	Director
Warren H. Gfeller	65	Director
David Lumpkins	63	Director
John J. Sherman	62	Director
John W. Somerhalder II	62	Director

Robert G. Phillips was elected Chairman, President and Chief Executive Officer of our general partner in June 2013 and has served on the Management Committee of Crestwood Holdings since May 2010. He served as Chairman, President and CEO of Legacy Crestwood from November 2007 until October 2013. Previously, Mr. Phillips served as President and Chief Executive Officer and a Director of Enterprise Products Partners L.P. from February 2005 until

June 2007 and Chief Operating Officer and a Director of Enterprise Products Partners L.P. from September 2004 until February 2005. Mr. Phillips also served on the Board of Directors of Enterprise GP Holdings L.P., the general partner of Enterprise Products Partners L.P., from February 2006 until April 2007. He previously served as Chairman of the Board and CEO of GulfTerra Energy Partners, L.P. (GTM), from 1999 to 2004, prior to GTM's merger with Enterprise Product Partners, LP, and held senior executive management positions with El Paso Corporation, including President of El Paso Field Services from 1996-2004. Prior to that he was Chairman, President and CEO of Eastex Energy, Inc. from 1981-1995. Mr. Phillips previously served as a Director of Pride International, Inc. from October 2007 to May 31, 2011, one of the world's largest offshore drilling contractors, and was a member of its audit committee. Mr. Phillips has served as a Director of Bonavista Energy Corporation , a Canadian independent oil and gas producer, since May 2015, and is a member of its compensation and governance committees. Mr. Phillips holds a

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B.B.A. from The University of Texas at Austin and a Juris Doctorate from South Texas College of Law. Mr. Phillips was selected to serve as the Chairman of the Board of our general partner because of his deep experience in the midstream business, expansive knowledge of the oil and gas industry, as well as his experience in executive leadership roles for public companies in the energy industry and operational and financial expertise in the oil and gas business generally.

J. Heath Deneke was appointed President, Chief Operating Officer, Pipeline Services Group in June 2015. He served as President, Chief Operating Officer, Pipeline Services Group from June 2015 to August 2017, President, Natural Gas Business Unit of our general partner from October 2013 to June 2015 and as Senior Vice President and Chief Commercial Officer of Legacy Crestwood from August 2012 until October 2013. Prior to joining Legacy Crestwood, Mr. Deneke served in various management positions at El Paso Corporation and its affiliates, including Vice President of Project Development and Engineering for the Pipeline Group, Director of Marketing and Asset Optimization for Tennessee Gas Pipeline Company, LLC and Manager of Business Development and Strategy for Southern Natural Gas Company, LLC. Mr. Deneke holds a bachelor’s degree in Mechanical Engineering from Auburn University.

Robert T. Halpin was appointed Executive Vice President, Chief Financial Officer in August 2017. He previously served as the Senior Vice President, Chief Financial Officer from March 2015 to August 2017, Vice President, Finance from January 2013 to March 2015 and as Vice President, Business Development from January 2012 to January 2013. Prior to joining Crestwood, from July 2009 to January 2012, he was an Associate at First Reserve and from July 2007 to June 2009, he was an investment banker in the Global Natural Resources Group at Lehman Brothers and subsequently, Barclays Capital following its acquisition of Lehman Brothers’ Investment Banking Division in September 2008. Mr. Halpin holds a B.B.A. in Finance from The University of Texas at Austin.

Steven M. Dougherty was appointed Senior Vice President, Chief Accounting Officer of our general partner in October 2013. He served as Senior Vice President, Interim Chief Financial Officer and Chief Accounting Officer of Legacy Crestwood from January 2013 to October 2013. Mr. Dougherty had served as Vice President and Chief Accounting Officer of Legacy Crestwood since June 2012. Prior to joining Legacy Crestwood, Mr. Dougherty was Director of Corporate Accounting at El Paso Corporation since 2001, with responsibility over El Paso’s corporate segment and in leading El Paso’s efforts in addressing complex accounting matters. Mr. Dougherty also had seven years of experience with KPMG LLP, working with public and private companies in the financial services industry. Mr. Dougherty holds a Master of Public Accountancy from The University of Texas at Austin and is a certified public accountant in the State of Texas.

Joel C. Lambert was appointed Senior Vice President, General Counsel and Chief Compliance Officer in August 2017. He served as Senior Vice President, General Counsel and Corporate Secretary of our general partner from October 2013 to August 2017. He served as a director of Legacy Crestwood from October 2010 to October 2013. From 2007 until October 2013, Mr. Lambert served as Vice President, Legal of First Reserve Corporation, a private equity company which invests exclusively in the energy industry. From 1998 to 2006, Mr. Lambert was an attorney in the Business and International Section of Vinson & Elkins LLP. In 1997, he was an Intern at the Texas Supreme Court, and has served as a Military Intelligence Specialist for the United States Army. Mr. Lambert holds a Bachelor of Environmental Design from Texas A&M University and a Juris Doctorate from The University of Texas School of Law.

William H. Moore was appointed Senior Vice President, Strategy and Corporate Development of our general partner in October 2013. He joined Legacy Inergy in 2005 as a legal analyst and has held various positions in corporate and business development, including Vice President, Corporate Development. Mr. Moore holds an M.B.A from Fort Hays State University, and a Juris Doctorate from the University of Kansas School of Law.

Alvin Bledsoe was appointed a director of our general partner in October 2013. He served as a director of Crestwood Midstream GP LLC (CMLP GP) from October 2013 to October 2015 and as a director of Legacy Crestwood from July 2007 until October 2013. Mr. Bledsoe currently serves as a director of SunCoke Energy, Inc. and SunCoke Energy Partners GP LLC, the general partner of SunCoke Energy Partners, L.P. Prior to his retirement in 2005, Mr. Bledsoe served as a certified public accountant and various senior roles for 33 years at PricewaterhouseCoopers (PwC). From 1978 to 2005, he was a senior client engagement and audit partner for large, publicly-held energy, utility, pipeline, transportation and manufacturing companies. From 1998 to 2000, Mr. Bledsoe served as Global Leader of PwC’s Energy, Mining and Utilities Industries Assurance and Business Advisory Services Group, and from 1992 to 2005 as a managing partner and regional managing partner. During his career, Mr. Bledsoe also served as a member of PwC’s governing body. Mr. Bledsoe was selected to serve as a director of our general partner due to his extensive background in public accounting and auditing, including experience advising publicly-traded energy companies.

Michael G. France was appointed as a director of our general partner in June 2013. He served as a director of CMLP GP from October 2013 to October 2015 and as a director of Legacy Crestwood from October 2010 to October 2013. Mr. France, a Managing Director of First Reserve, a global private equity and infrastructure firm focused exclusively on energy, has been with the firm since 2007. Additionally, Mr. France has served on the Management Committee of Crestwood Holdings since May 2010. From 2003 to 2007, Mr. France served as a Vice President in the Natural Resources Group, Investment Banking Division, at Lehman Brothers. From 1999 to 2001, he served as a Senior Consultant at Deloitte & Touche LLP. Mr. France previously served on the board of directors of Cobalt International Energy, Inc. Mr. France holds a B.B.A. (Cum Laude) in Finance from The University of Texas at Austin and a Master of Business Administration from Jones Graduate School of Management at Rice University. Mr. France was elected to serve as a director of our general partner due to his years of experience in financing energy related companies including his energy investment experience at First Reserve and his general knowledge of upstream and midstream energy companies.

Warren H. Gfeller has been a member of our general partner's board of directors since March 2001. He served as a director of CMLP GP from December 2011 to October 2015. He has engaged in private investments since 1991. From 1984 to 1991, Mr. Gfeller served as president and chief executive officer of Ferrellgas, Inc., a retail and wholesale marketer of propane and other natural gas liquids. Mr. Gfeller began his career with Ferrellgas in 1983 as an executive vice president and financial officer. Prior to joining Ferrellgas, Mr. Gfeller was the Chief Financial Officer of Energy Sources, Inc. and a CPA at Arthur Young & Co. He has served as a director of HC2 Holdings, Inc. since June 2016 and previously served as a director of Inergy Holdings GP, LLC, Zapata Corporation and Duckwall-Alco Stores, Inc. Mr. Gfeller worked for many years in the energy industry. This experience has given him a unique perspective on our operations, and, coupled with his extensive financial and accounting training and practice, has made him a valuable member of our board of directors.

David Lumpkins has been a director of our general partner since November 2015. He is Chairman of PetroLogistics II, LLC, a petrochemical development company. He was the co-founder and Executive Chairman of Petrologistics, a NYSE listed company which was acquired by Flint Hills Resources in July 2014. Mr Lumpkins was also previously the co-founder and Chairman of PL Midstream, a pipeline transportation and storage company based in Louisiana, which was sold to Boardwalk Partners in 2012. Prior to the formation of these companies, Mr. Lumpkins worked in the investment banking industry for 17 years, principally for Morgan Stanley and Credit Suisse. In 1995, Mr. Lumpkins opened Morgan Stanley's Houston office and served as head of the firm's southwest region. He is a graduate of The University of Texas where he also received his MBA. Mr. Lumpkins also serves as a director of Westlake Chemical Partners LP. Mr. Lumpkins' extensive experience in the petrochemical, energy midstream and finance industries adds significant value to the boards of directors.

John J. Sherman has served as a director of our general partner since March 2001 and previously served on the board of directors of CMLP's general partner. He served as Chief Executive Officer and President of our general partner from March 2001 until June 2013 and of our predecessor from 1997 until July 2001. Prior to joining our predecessor, he was a vice president with Dynegy Inc. from 1996 through 1997. He was responsible for all downstream propane marketing operations, which at the time were the country's largest. From 1991 through 1996, Mr. Sherman was the president of LPG Services Group, Inc., a company he co-founded and grew to become one of the nation's largest wholesale marketers of propane before Dynegy acquired LPG Services in 1996. From 1984 through 1991, Mr. Sherman was a vice president and member of the management committee of Ferrellgas. He also served as President, Chief Executive Officer and director of Inergy Holdings GP, LLC. He is currently the Chief Executive Officer of MLP Holdings, LLC, Vice Chairman of the Cleveland Indians Baseball Club and a director of Great Plains Energy Inc. and Tech Accel LLC. We believe the breadth of Mr. Sherman's experience in the energy industry and his past employment described above, as well as his current board of director positions, has given him valuable knowledge about our business and our industry that makes him an asset to our board of directors.

John W. Somerhalder II was appointed as a director of our general partner in October 2013. He has served as a director of CenterPoint Energy, Inc. since October 2016, a director of SunCoke Energy Partners GP LLC, the general partner of SunCoke Energy Partners, L.P. since August 2017 and as a director of Legacy Crestwood from July 2007 to

October 2013. Mr. Somerhalder served as the interim Chief Executive Officer of Colonial Pipeline Company from February 2017 through October 2017 and as the President, Chief Executive Officer and a director of AGL Resources Inc. (AGL Resources), a publicly-traded energy services holding company whose principal business is the distribution of natural gas, from March 2006 to December 2015 and as Chairman of the Board of AGL Resources from November 2007 to December 2015. From 2000 to May 2005, Mr. Somerhalder served as the Executive Vice President of El Paso Corporation, where he continued service under a professional services agreement from May 2005 to March 2006. From 2001 to 2005, he served as the President of El Paso Pipeline Group. From 1996 to 1999, Mr. Somerhalder served as the President of Tennessee Gas Pipeline Company, an El Paso subsidiary company. From April 1996 to December 1996, Mr. Somerhalder served as the President of El Paso Energy Resources Company. From 1992 to 1996, he served as the Senior Vice President, Operations and Engineering, of El Paso Natural Gas Company. From 1990 to 1992, Mr. Somerhalder served as the Vice President, Engineering of El Paso Natural Gas Company. From 1977 to 1990, Mr. Somerhalder held various other positions at El Paso Corporation and its subsidiaries until being named an officer in 1990. Mr. Somerhalder was selected to serve as a director of our general partner due to his years of experience in the oil and gas industry and his extensive business and management expertise, including as President, Chief Executive Officer and a director of a publicly-traded energy company.

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Independent Directors

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors on the board, nor that we establish or maintain a nominating or compensation committee of the board. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be independent as defined by the NYSE. The board of directors has determined that Alvin Bledsoe, Warren Gfeller, David Lumpkins and John W. Somerhalder II qualify as independent pursuant to independence standards established by the NYSE as set forth in Section 303A.02 of the manual. To be considered an independent director under the NYSE listing standards, the board of directors must affirmatively determine that a director has no material relationship with us other than as a director. In making this determination, the board of directors adheres to all of the specific tests for independence included in the NYSE listing standards and considers all other facts and circumstances it deems necessary or advisable.

Board Committees

Audit Committee

The members of the audit committee are Alvin Bledsoe (Chairman), David Lumpkins and John Somerhalder II. Our board has determined that each of the members of our audit committee meet the independence standards of the NYSE and is financially literate. In addition, the board has determined that Mr. Bledsoe is an audit committee financial expert based upon the experience stated in his biography. The audit committee’s primary responsibilities are to monitor: (a) the integrity of our financial reporting process and internal control system; (b) the independence and performance of the independent registered public accounting firm; and (c) the disclosure controls and procedures established by management. Our audit committee charter may be found on our website at www.crestwoodlp.com.

Compensation Committee

Although we are not required by NYSE listing standards to have a compensation committee, two members of our board of directors also serve as members of our compensation committee, which oversees compensation decisions for the executive officers of our general partner, as well as the compensation plans described below. The current members of the compensation committee are Warren Gfeller (Chairman) and Alvin Bledsoe. Our compensation committee charter may be found on our website at www.crestwoodlp.com.

Conflicts Committee

Our general partner has established a conflicts committee to review specific matters which the board of directors believes may involve conflicts of interest. The members of our conflicts committee are David Lumpkins and John Somerhalder II (Chairman). The conflicts committee will determine if the resolution of any conflict of interest submitted to it is fair and reasonable to us. In addition to satisfying certain other requirements, the members of the conflicts committee must meet the independence standards for service on an audit committee of a board of directors, which standards are established by the NYSE. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

Finance Committee

Our general partner has established a finance committee to assist the board of directors in fulfilling its oversight responsibilities across the principal areas of corporate finance and risk management. The members of the finance committee are David Lumpkins (Chairman) and Warren Gfeller.

Board Leadership Structure

The board has no policy that requires that the positions of the Chairman of the Board (the Chairman) and the Chief Executive Officer be separate or that they be held by the same individual. The board believes that this determination should be based on circumstances existing from time to time, including the composition, skills and experience of the board and its members, specific challenges faced by us or the industry in which it operates, and governance efficiency. Based on these factors, Robert Phillips serves as our Chairman and Chief Executive Officer.

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Risk Oversight

We face a number of risks, including environmental and regulatory risks, and others, such as the impact of competition. Management is responsible for the day-to-day management of risks our company faces, while the board of directors, as a whole and through its committees, has responsibility for the oversight of risk management. In fulfilling its risk oversight role, the board of directors must determine whether risk management processes designed and implemented by our management are adequate and functioning as designed. Senior management regularly delivers presentations to the board of directors on strategic matters, operations, risk management and other matters, and is available to address any questions or concerns raised by the board.

Our board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists with risk management oversight in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements and our risk management policy relating to our hedging program. The compensation committee assists the board of directors with risk management relating to our compensation policies and programs.

Meetings of Non-Management Directors

Our non-management directors meet in regularly scheduled sessions. Our non-management directors have appointed Warren Gfeller as the lead director to preside at such meetings. In addition, our independent directors meet in executive session at least once a year.

Communication with the Board of Directors

We have established a procedure by which unitholders or interested parties may communicate directly with the board of directors, any committee of the board, any of the independent directors or any one director serving on the board of directors by sending written correspondence addressed to the desired person, committee or group to the attention of Joel C. Lambert, Senior Vice President, General Counsel, 811 Main Street, Suite 3400, Houston, TX 77002. Communications are distributed to the board of directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Code of Ethics/Governance Guidelines

We have adopted a Code of Business Conduct and Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions, as well as to all of our other employees. Additionally, the board of directors has adopted corporate governance guidelines for the directors and the board. The Code of Business Conduct and Ethics and corporate governance guidelines may be found on our website at www.crestwoodlp.com.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our company’s directors and executive officers, and persons who own more than 10% of any class of equity securities of our company registered under Section 12 of the Exchange Act, to file with the Securities and Exchange Commission initial reports of ownership and report of changes in ownership in such securities and other equity securities of our company. Securities and Exchange Commission regulations require directors, executive officers and greater than 10% unitholders to furnish our company with copies of all Section 16(a) reports they file. To our knowledge, based solely on review of the reports furnished to us and written representations that no other reports were required, during the fiscal year ended December 31, 2017, all section 16(a) filing requirements applicable to our directors, executive officers and greater than 10% unitholders, were met.

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Item 11. Executive Compensation

Compensation Discussion and Analysis

Introduction

We do not directly employ any of the persons responsible for managing our business. Crestwood Equity GP LLC, our general partner, currently manages our operations and activities, and its board of directors and officers make decisions on our behalf. The compensation of the directors and the executive officers of our general partner is determined by the board of directors of our general partner based on the recommendations of our compensation committee.

All of our executive officers also serve in the same capacities as executive officers of our subsidiaries and the compensation of the Named Executive Officers (NEOs) discussed below reflects total compensation for services to all Crestwood entities described in more detail below.

For purposes of this Compensation Discussion and Analysis our NEOs for fiscal 2017 were comprised of:

- Robert G. Phillips, our current President and Chief Executive Officer and Director (Principal Executive Officer);
- Robert T. Halpin, our Executive Vice President and Chief Financial Officer (Principal Financial Officer);
- J. Heath Deneke, our Executive Vice President and Chief Operating Officer;
- William H. Moore, our Senior Vice President, Strategy and Corporate Development; and
- Steven M. Dougherty, our Senior Vice President and Chief Accounting Officer

Compensation Philosophy and Objectives

We employ a compensation philosophy that emphasizes pay for performance. The primary measure of our long-term performance is our ability to maintain sustainable cash distributions to our unitholders and the related unitholder value realized. We believe that by tying a substantial portion of each NEO’s total compensation to financial, operational and safety performance metrics that support sustainability in distributable cash, our pay-for-performance approach aligns the interests of our executive officers with that of our unitholders. Accordingly, the objectives of our total compensation program consist of:

- aligning executive compensation incentives with the creation of unitholder value;
- balancing short and long-term performance;
- tying short-and long-term compensation to the achievement of performance objectives (company, business unit, department and/or individual); and
- attracting and retaining the best possible executive talent for the benefit of our unitholders.

By accomplishing these objectives, we intend to optimize long-term unitholder value.

Compensation Setting Process

Role of Management

In order to make pay recommendations, management, with assistance from management’s consultant, provides the CEO with data from the annual proxy statements and annual reports of companies in our comparator group along with pay information compiled from nationally recognized executive and industry-related compensation surveys. The survey data is used to confirm that pay practices among companies in the comparator group are aligned with the market as a whole.

Chief Executive Officer’s Role in the Compensation Setting Process

Our CEO plays a significant role in the compensation setting process. The most significant aspects of his role are:

- assisting in establishing business performance goals and objectives;
- evaluating executive officer and company performance;
- recommending compensation levels and awards for executive officers other than himself; and
- implementing the approved compensation plans.

Our CEO makes recommendations to the compensation committee with respect to financial metrics to be used and determination of performance for performance-based awards as well as other recommendations regarding non-CEO executive

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compensation, which may be based on our performance, individual performance and the peer group compensation market analysis. The compensation committee considers this information when establishing the total compensation packages of our executive officers. The CEO's performance and compensation is reviewed, evaluated and established separately by the compensation committee and the full board based on criteria similar to those used for non-CEO executive compensation. The board of directors of our general partner reviews all aspects of executive compensation based on the reports from the compensation committee.

Role of the Compensation Committee

For all NEOs, except the CEO, the compensation committee reviews the CEO's recommendations, supporting market data, and individual performance assessments. In addition, the compensation committee reviews the reasonableness of the CEO's pay recommendations based on a competitive market study that includes proxy and annual report data from the approved comparator group and published compensation survey data. For the CEO, in fiscal 2017 the board of directors met in executive session without management present to review the CEO's performance. In this session, the board of directors reviewed:

- Evaluations of the CEO completed by the board members;
- The CEO's written assessment of his/her own performance compared with the stated goals; and
- Business performance of the Company relative to established targets.

The compensation committee used these evaluations and the competitive market study to determine the CEO's long-term incentive amounts, annual cash incentive target, base pay, and any performance adjustments to be made to the CEO's annual cash incentive payment.

Role of the Compensation Consultant

In June 2017, we engaged Willis Towers Watson to serve as our compensation consultant. Prior to June 2017, Aon Hewitt served as our compensation consultant. Our compensation committee and management believe it is beneficial to have an independent third-party analysis to assist in evaluating and setting executive compensation. Management, in consultation with the compensation committee, chose Willis Towers Watson and Aon Hewitt based on their extensive experience in providing executive compensation advice, including specific experience in the oil and gas industry. For fiscal 2017, Aon Hewitt provided management and the compensation committee with an analysis of our executive compensation programs, including total direct compensation comprised of base salary, annual incentive and long-term incentive compensation, in order to assess the competitiveness of our programs and to provide conclusions and recommendation. Our compensation committee has taken and will take into consideration the discussions, guidance and compensation studies produced by our compensation consultants in order to make compensation decisions. The compensation committee has assessed the independence of the compensation consultants and has concluded that the compensation consultants' work for the compensation committee does not raise any conflict of interest.

Competitive Benchmarking and Peer Group

Our compensation committee considers competitive industry data in making executive pay determinations. Pursuant to our compensation committee's decisions to maintain a peer group for executive compensation purposes and in view of evolving industry and competitive conditions, Aon Hewitt, with the assistance of management, proposed certain peer group companies for our compensation committee's review.

After discussion with Aon Hewitt and reviewing its recommendation of a peer group based on companies with annual revenues, assets and net income similar to ours and taking into account geographic footprint and employee count, our compensation committee determined that the peer group listed below was the most appropriate for purposes of the 2017 executive compensation analyses.

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Boardwalk Pipeline Partners LP	Midcoast Energy Partners, L.P.
Buckeye Partners, L.P.	NuStar Energy L.P.
DCP Midstream Partners, LP	ONEOK Inc.
Enable Midstream Partners, LP	Summit Midstream Partners, LP
EnLink Midstream Partners, LP	Tallgrass Energy Partners, LP
EQT Midstream Partners, LP	Targa Resources Corp.
Genesis Energy LP	Andeavor Logistics LP
Magellan Midstream Partners, L.P.	Western Gas Partners, LP

Aon Hewitt compiled compensation data for the peer group from a variety of sources, including proxy statements and other publicly filed documents, and compiled published survey compensation data from multiple sources. This compensation data was then presented to the compensation committee and used to compare the compensation of our NEOs to our peer group where the peer group had individuals serving in similar positions and to the market.

Elements of Compensation

The principal elements of compensation for the NEOs are the following:

- base salary;
- incentive awards;
- long-term incentive plan awards; and
- retirement and health benefits.

In addition, certain NEOs have received incentive units from Crestwood Holdings, a subsidiary of First Reserve, which plays a key role in enabling our general partner to attract, recruit, hire and retain qualified executive officers.

Base Salary

Base salary is designed to compensate executives commensurate with the level of the position they hold and for sustained individual performance (including experience, scope of responsibility, results achieved and potential). The initial base salaries for our NEOs were determined in 2013 and documented in employment agreements we entered into with each of our executive officers in January 2014 (the Executive Employment Agreements). For a more detailed description of the Executive Employment Agreements, see “Narrative Disclosure to Summary Compensation and Grants of Plan Based Awards Tables-Employment Agreements.”

Base salaries for our NEOs are reviewed on an annual basis and at the time of promotion or other change in responsibilities. In determining the amount of any adjustments, the compensation committee uses market data as a tool for assessing the reasonableness of the base salary amounts of the NEOs as compared to the compensation of executives in similar positions with similar responsibility levels in our industry. However, the final determination of base salary amounts was within the compensation committee’s discretion. Based on our objective to maintain target average base compensation at the 50th percentile of the market data, the compensation committee approved a standard 3% merit increase for our NEOs effective January 1, 2017. Accordingly, the annual base salaries were increased as follows: Mr. Phillips ($674,650), Mr. Halpin ($412,000), Mr. Deneke ($489,250), Mr. Moore ($360,500) and Mr. Dougherty ($386,250).

With respect to Mr. Deneke, in July 2017 his annual base salary was increased to $525,000 in connection with his promotion to Executive Vice President, Chief Operating Officer.

Annual Incentive Awards

Incentive bonuses are granted based on a percentage of each NEO's base salary. Incentive awards are designed to reward the performance of key employees, including the NEO's, by providing annual incentive opportunities for the partnership's achievement of its annual financial, operational, and individual performance goals. In particular, these bonus awards are provided to the NEOs in order to provide competitive incentives to these individuals who can significantly impact performance and promote achievement of our short-term business objectives.

Annual incentive target payouts were initially established for each of our NEOs pursuant to their Employment Agreements. For a more detailed description of the Executive Employment Agreements, see "Narrative Disclosure to Summary Compensation

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and Grants of Plan Based Awards Tables-Executive Employment Agreements." The annual target bonus amounts of our NEOs are reviewed on an annual basis and at the time of promotion or other change in responsibilities. In determining the amount of any adjustments, the compensation committee uses market data as a tool for assessing the reasonableness of the annual incentive targets of the NEOs as compared to executives in similar positions with similar responsibility levels in our industry. However, the final determination of annual target bonus amounts is within the compensation committee's discretion.

Actual bonuses for 2017 were determined based on our achievement of compensation committee approved key performance indicators (KPIs) and a board discretionary component. The KPIs for fiscal 2017 were Adjusted EBITDA, operational and administrative costs, total shareholder return relative to peers and safety. Each KPI is then weighted based on the relative impact to our overall compensation philosophy and objectives. Actual results between the minimum and maximum target thresholds are pro-rated based on the percentage of target reached. Actual results above the maximum threshold are capped at 140% and results below 40% achievement result in 0% achievement for that KPI, excluding total shareholder return relative to peers. The board discretionary component allows our board of directors the ability to increase the total recommended bonus pool as much as 25%, or decrease the bonus pool by as much as 20% based on qualitative factors deemed relevant by the board.

2017 Annual Incentive Awards KPIs	Weighting	Target
Adjusted EBITDA	60 %	$380.0
Operational and Administrative Costs	20 %	$248.0
Relative Total Shareholder Return*	5 %	100 %
Total Recordable Incident Rate	5 %	2.0
At-Fault Vehicle Incident Rate	5 %	1.4
Lost Time Injury Rate	5 %	1.2
	100 %	—

* Peers include Boardwalk Pipeline Partners LP, Buckeye Partners LP, DCP Midstream, LP, Enable Midstream Partners, LP, EnLink Midstream Partners LP, EQP Midstream Partners LP, Genesis Energy LP, Magellan Midstream Partners, L.P., Midcoast Energy Partners, L.P., NuStar Energy L.P., ONEOK Inc., Summit Midstream Partners LP, Tallgrass Energy Partners, Targa Resources Corp., Andeavor Logistics LP and Western Gas Partners LP.

Based on the company's KPI achievement, the actual annual incentive bonus pool for fiscal 2017 was established at 110% of target amount. The actual bonus amount paid to the individual NEO is then adjusted based on the individual performance review for such NEO. For 2017, each NEO received the highest performance rating of "1" which increased the actual percentage for such individuals to 135% of target, which is equivalent to the company-wide target payout for "1" performance ratings.

Because of changes made to Mr. Deneke's compensation in July 2017, the target bonus amount for each of our other NEOs (other than Mr. Deneke) was then further adjusted to avoid Mr. Deneke receiving a disparate award as compared to the other NEOs. The adjustments made assumed that each of our NEOs (other than Mr. Deneke) received their respective new 2018 target bonus amount as of July 2017 and that 2018 base compensation changes were made as of July 2017 (6 months using 2017 target bonus and 6 months using 2018 target bonus). These adjustments resulted in actual 2017 bonus payouts as follows:

Name	2018 Base Salary ($)	Pro-Rated Target Bonus ($)	Percentage of Target Bonus	Total ($)
Robert G. Phillips	750,000	712,500	135%	961,875
Robert T. Halpin	450,000	410,400	135%	554,040
J. Heath Deneke	525,000	548,175	135%	740,036

William H. Moore	385,000	373,000	135%	503,550
Steven M. Dougherty	410,000	318,400	135%	429,840

In addition to annual incentive awards, from time to time the compensation committee may award one-time project completion bonuses. The amount of these awards are recommended by management to the compensation committee based on the size of the project, the strategic importance of the project to the company and the respective individual's efforts in sourcing and completing the project.

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In the fourth quarter of 2017, the company completed the sale of US Salt LLC to Kissner Group Holdings LP for net proceeds of approximately $223.6 million. The divestiture was critical to provide funds to the company to reinvest in on-going organic growth projects in the Bakken and Delaware Basin. Due to his significant efforts in this project, the compensation committee awarded Mr. Moore a $200,000 completion bonus.

Mr. Deneke receives an additional $10,000 bonus per annum as additional compensation pursuant to the terms of his new employment agreement with us.

Long-Term Incentive Plan Awards

Long-term incentive awards for the NEOs are granted under the Crestwood Equity Partners LP Long Term Incentive Plan in order to promote achievement of our primary long-term strategic business objective of increasing distributable cash flow and increasing unitholder value. This plan was designed to align the economic interests of key employees and directors with those of our common unitholders and to provide an incentive to management for continuous employment with the general partner and its affiliates. Long-term incentive compensation is based upon the common units representing limited partnership interests in us. For fiscal 2017, awards consisted of grants of restricted common units which vest based upon continued service and performance units which vest based on performance conditions. Long-term incentive plan awards are designed to attract and retain executive talent and to align their economic interests with those of common unitholders.

The initial long-term equity incentive targets for our NEOs were established in their Employment Agreements. For a more detailed description of the Executive Employment Agreements, see “Narrative Disclosure to Summary Compensation and Grants of Plan Based Awards Tables-Employment Agreements.” The annual target long-term equity incentives for our NEOs are reviewed on an annual basis and at the time of promotion or other changes in responsibilities. In determining the amount of any adjustments, the compensation committee uses market data as a tool for assessing the reasonableness of long-term incentive targets of the NEOs as compared to executives in similar positions with similar responsibility levels in our industry. However, the final determination of long-term equity awards is within the compensation committee’s discretion. Based on our objective of setting long-term incentive awards at the median of the market data, no changes were made to the annual target long-term incentive awards in 2017. Accordingly, the following restricted units awards were made to our NEOs in 2017:

Name	Target Equity Percentage	2017 Restricted Units Awarded (#)	Value at Grant Date ($)
Robert G. Phillips	300%	76,908	1,991,917
Robert T. Halpin	250%	48,532	1,256,979
J. Heath Deneke	250%	135,567	3,421,185
William H. Moore	180%	29,355	760,294
Steven M. Dougherty	175%	30,382	786,894

Mr. Deneke’s restricted unit awards includes 75,000 restricted units awarded in July 2017 in connection with his new employment agreement, which vests on June 30, 2020. All other restricted unit awards vest ratably over a three-year period.

In addition to the annual restricted unit grants, our NEOs are also eligible to receive performance phantom unit awards. Performance phantom units vest over a three-year performance period and are paid out based on a performance multiplier ranging between 50% and 200%, determined based on the actual performance in the third year of the performance period compared to pre-established performance goals. For all performance units granted in 2017, the performance goals were based on achieving a specified level of distributable cash flow per unit, Adjusted EBITDA, return on capital invested, and three-year relative total shareholder return, based on the Partnership's percentile ranking as compared with companies that are contained in the Alerian MLP Index at the time the goals were set. The compensation committee selected these metrics because we believe these are the key value indicators for our unitholders and will most closely align the interests of our NEOs with those of our unitholders. The compensation committee then weighted the four performance measures as follows:

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Performance Unit Metric	Weighting
Adjusted EBITDA	30%
Distributable Cash Flow per Unit	30%
Return on Capital Invested	20%
Total Unitholder Return	20%

For all performance unit grants, the last year of the respective performance period is used to measure whether the performance goal is achieved. There is generally no payout for performance below the threshold performance goal level. The payout multiplier for performance equal or greater than threshold is determined on a linear scale between performance levels.
In making the 2017 performance unit grants to our NEOs, the compensation committee considered:
- peer benchmarking data specific to each named executive officer; and
- each NEO’s contribution to our long-term growth.

Based on this analysis, the compensation committee approved the following grants of performance units our named executive officers on February 15, 2017:

	Performance Units			
Name	Threshold (#)	Target (#)	Maximum (#)	Value at Grant Date ($)
Robert G. Phillips	44,250	89,041	178,082	2,710,939
Robert T. Halpin	13,698	27,397	54,794	834,122
J. Heath Deneke	16,634	33,268	66,536	1,012,884
William H. Moore	10,274	20,548	41,096	625,611
Steven M. Dougherty	10,274	20,548	41,096	625,611

Risk Assessment Related to our Compensation Structure

We believe that the compensation plans and programs for our executive officers, as well as other employees, are appropriately structured and are not reasonably likely to result in a material risk. We believe these compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could reward poor judgment. We also believe that we have allocated compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for our executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment.

Severance and Change of Control Benefits

Our NEOs are entitled to certain severance and change in control benefits as provided their respective Executive Employment Agreements. For a detailed description of the Executive Employment Agreements for our NEOs, see “Potential Payments upon a Change in Control or Termination during Fiscal 2017.”

Other Compensation Related Matters

Retirement and Health Benefits

We offer a variety of health and welfare and retirement programs to all eligible employees. The NEOs are eligible for these programs on the same basis as other employees. We maintain a 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax advantaged basis. We match 6% of the deferral to the retirement plan (not to exceed the maximum amount permitted by law) made by eligible participants. Our executive officers are also eligible to participate in additional employee benefits available to our other employees.

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Perquisites and Other Compensation

We do not provide perquisites or other personal benefits to any of the NEOs.

Tax Deductibility of Compensation

With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not meet the definition of a "corporation" under Section 162(m). Thus the compensation that we pay to our employees is not subject to the deduction limitations under Section 162(m) of the Code.

Compensation Committee Report

We have reviewed and discussed the foregoing Compensation Discussion and Analysis with management. Based on our review and discussion with management, we have recommended that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2017.

Members of the Compensation Committee

Warren Gfeller
Alvin Bledsoe

Summary Compensation Table for Fiscal 2017
The following table sets forth the cash and non-cash compensation earned by our NEOs for the fiscal years ended December 31, 2017, 2016 and 2015.

Name and Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Unit Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)(2)	Total ($)
Robert G. Phillips	2017	674,650	1,000	4,702,856	961,875	44,439	6,384,820
President, Chief Executive	2016	655,000	—	1,589,964	655,000	17,088	2,917,052
Officer and Director	2,015	655,000	—	2,935,211	655,000	10,093	4,255,304
Robert T. Halpin Executive	2017	412,000	1,000	2,091,101	554,040	16,344	3,074,485
Vice President, Chief	2016	400,000	115,000	860,017	360,000	15,744	1,750,761
Financial Officer	2015	400,000	—	1,057,804	360,000	16,044	1,833,848
J. Heath Deneke Executive	2017	504,375	11,000	4,434,069	740,036	16,387	5,705,867
Vice President and Chief	2016	475,000	100,000	1,062,601	427,500	15,780	2,080,881
Operating Officer	2015	475,000	—	1,477,254	427,500	16,080	2,395,834
William H. Moore	2017	360,500	201,000	1,385,905	503,550	16,254	2,467,209
Senior Vice President,	2016	350,000	100,000	713,284	350,000	15,654	1,528,938
Strategy and Corporate Development	2015	350,000	—	482,164	350,000	15,954	1,198,118
Steven M. Dougherty	2017	386,250	1,000	1,412,505	429,840	16,470	2,246,065
Senior Vice President,	2016	375,000	—	530,990	300,000	15,780	1,221,770
Chief Accounting Officer	2015	375,000	—	1,156,195	330,000	16,080	1,877,275

(1) The material terms of our outstanding LTIP awards to our executive officers are described in "Compensation Discussion and Analysis - Long-Term Incentive Plan Awards." Unit award amounts reflect the aggregate grant date fair value of unit awards granted during the periods presented calculated in accordance with Accounting Standards

Codification Topic 718, Compensation - Stock Compensation (ASC 718), disregarding forfeitures and assuming target performance for phantom performance units. The unit awards vest 20% based on market conditions and 80% based on performance conditions. Assuming maximum performance with respect to the performance based vesting conditions, the aggregate grant date fair value of the unit awards granted during 2017 would be $3,962,252 for Mr. Phillips, $1,214,235 for Mr. Halpin, $1,474,438 for Mr. Deneke, $910,687 for Messrs. Moore and Dougherty, respectively. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 13 for a discussion of the assumptions used to determine the FASB ASC 718 value of the awards.

(2) "All Other Compensation" for Fiscal Year 2017 consisted of the following:

Name	401(k) Matching Contributions ($)	Group Term Life Insurance ($)	Other ($)*	Total ($)
Robert G. Phillips	16,200	1,188	27,051	44,439
Robert T. Halpin	16,200	144	—	16,344
J. Heath Deneke	16,200	187	—	16,387
William H. Moore	16,200	54	—	16,254
Steven M. Dougherty	16,200	270	—	16,470

*Reflects the incremental cost to Crestwood for personal use of corporate aircraft.

Grants of Plan-Based Awards Table for Fiscal 2017

The following table provides information concerning each grant of an award made to our NEOs during fiscal 2017.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards[(1)]			Estimated Future Payout Under Equity Incentive Plan Awards[(2)]				
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	All Other Unit Awards (#)[(3)]	Grant Date Fair Value of Unit and Option Awards ($)[(4)]
Robert G. Phillips	01/05/17							76,908	1,991,917
	02/15/17				44,250	89,401	178,082		2,710,939
		286,200	712,500	998,700					
Robert T. Halpin	01/05/17							48,532	1,256,979
	02/15/17				13,698	27,397	54,794	—	834,123
		164,160	410,400	574,560					
J. Heath Deneke	01/05/17							60,567	1,568,685
	02/15/17				16,634	33,268	66,536		1,012,884
	07/24/17							75,000	1,852,500
		219,270	548,175	767,445					
William H. Moore	01/05/17							29,355	760,295
	02/15/17				10,274	20,548	41,096		625,611
		149,200	373,000	522,200					
Steven M. Dougherty	01/05/17							30,382	786,894
	02/15/17				10,274	20,548	41,096		625,611
		127,360	318,400	445,760					

(1) Actual amounts paid pursuant to the annual incentive bonus are reported in the "Non-Equity Incentive Plan Compensation" column of the Summary Compensation Table. The amount of the annual bonus may be increased at the discretion of the compensation committee, irrespective of actual KPI performance, as described above in the "Compensation Discussion and Analysis - Incentive Awards."

(2) Represents grants of performance phantom units granted under the Long Term Incentive Plan. The vesting of the performance units are subject to the attainment of pre-established performance goals based on adjusted distributable cash flow per unit, Adjusted EBITDA, adjusted return on capital employed and total shareholder return relative to the Alerian MLP Index during the third year of a three fiscal year period. The grant date fair value of the performance unit awards reflected in the table is based on a target payout of such awards.

(3) Represents grants of restricted units granted under the Long Term Incentive Plan. The restricted units vest ratably (33.33%) over a three year period beginning on the first anniversary of the grant date. Mr. Deneke's July 24, 2017

restricted unit award vests in full on June 30, 2020.

(4) Unit award amounts reflect the aggregate grant date fair value of unit awards granted during 2017 calculated in accordance with ASC 718, disregarding forfeitures. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 13 for a discussion of the assumptions used to determine the value of the awards.

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Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

Employment Agreements

During January 2014, Crestwood Operations, LLC (Crestwood Operations) entered into new employment agreements (the Executive Employment Agreements) with each of our named executive officers. The Executive Employment Agreements each have an initial term ending December 31, 2015 and will renew automatically for additional one-year periods thereafter if neither party gives advance notice of non-renewal. The Executive Employment Agreements provide for the base salary, target bonus amounts and a target equity compensation grant described in our "Compensation Discussion and Analysis."

Under the terms of the Executive Employment Agreements, if the named executive officer's employment is terminated during the initial term or a subsequent one-year renewal by Crestwood Operations without "employer cause" or the executive resigns due to "employee cause" or the named executive officer's employment with Crestwood Operations terminates as a result of Crestwood Operations' election not to renew the Executive Employment Agreement or due to the executive's death or permanent disability, the executive will be entitled to receive, subject to the executive's execution of a release of claims, severance equal to two (or, in the case of Mr. Phillips, three) times the sum of the executive's base salary and average annual bonus for the prior two years, payable in equal installments over an 18-month period following termination. In addition, the named executive officer would be entitled to certain subsidized medical benefits over such 18-month period. If the named executive officer fails to comply with covenants in the Executive Employment Agreement, the release of claims or similar agreement, he forfeits the right to receive any severance payment installments following such failure to comply.

On July 21, 2017, Crestwood Operations entered into the Second Amended and Restated Employment Agreement with Heath Deneke (the Deneke Employment Agreement). In consideration of Mr. Deneke entering into the Deneke Employment Agreement and as compensation for his ongoing service, the Partnership issued 75,000 restricted units to Mr. Deneke which shall become vested on June 30, 2020. In addition, if, on or before July 1, 2019, there is a Change in Control (as defined in the Deneke Employment Agreement), the Partnership will issue 125,000 restricted units to Mr. Deneke, which units will be fully vested on their issuance date.
Under the terms of the Deneke Employment Agreement, if Mr. Deneke's employment is terminated the Company without "employer cause" or Mr. Deneke resigns due to "employee cause" or Mr. Deneke's employment terminates as a result of death or permanent disability, Mr. Deneke will be entitled to receive severance equal to two times the sum of his base salary and average annual bonus for the prior two years, payable in equal installments over an 12-month period following termination. However, if Mr. Deneke's employment is terminated during the period beginning three months prior to a Change in Control and ending twelve months after a Change in Control, then the severance amount payable shall be increased to three (3) times his base salary and average annual bonus for the prior two years. If Mr. Deneke fails to comply with covenants in the Deneke Employment Agreement, the release of claims or similar agreement, he forfeits the right to receive any severance payment installments following such failure to comply.

On February 22, 2018, Crestwood Operations entered into an Omnibus Amendment to each Executive Employment Agreement ("Omnibus Amendment"), other than Mr. Deneke's Executive Employment Agreement, which has been replaced by the Deneke Employment Agreement. Pursuant to the Omnibus Amendment, if, on or before July 1, 2019, there is a Change in Control (as defined in the Omnibus Amendment), the Partnership will issue 150,000 restricted units to Mr. Phillips, 100,000 restricted units to Mr. Halpin, and 75,000 restricted units to Messrs. Moore and Dougherty, respectively, which units will be fully vested on their issuance date. Furthermore, if the employment Messrs. Halpin, Moore or Dougherty is terminated during the period beginning three months prior to a Change in Control and ending twelve months after a Change in Control, then the severance amount payable shall be increased to three (3) times base salary and average annual bonus for the prior two years.

The foregoing summary of the material provisions of the Executive Employment Agreements, the Deneke Employment Agreement and the Omnibus Agreement is intended to be general in nature and is qualified by the full text of the Executive Employment Agreements, , the Deneke Employment Agreement and the Omnibus Agreement, each of which is incorporated by reference herein as an exhibit to this report.

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Outstanding Equity Awards at 2017 Fiscal Year-End

The following table summarizes the outstanding equity awards as of the end of Fiscal 2017 for the each of our NEOs. The table includes restricted units, phantom units and phantom performance units granted under the Crestwood Equity Partners LP Long Term Incentive Plan.

Name	UNIT AWARDS Number of Units That Have Not Vested (#)(1)	Market Value of Units That Have Not Vested ($)(2)
Robert G. Phillips	283,171	7,305,812
Robert T. Halpin	132,149	3,409,444
J. Heath Deneke	239,641	6,182,738
William H. Moore	82,675	2,133,015
Steven M. Dougherty	94,860	2,447,388

(1) Mr. Phillips' restricted units vest as follows: 25,636 on January 5, 2018, 37,883 on January 15, 2018, 3,898 on January 16, 2018, 4,720 on January 16, 2018, 25,636 on January 5, 2019, 37,884 on January 15, 2019 and 25,636 on January 5, 2020. Mr. Phillips' phantom units vest as follows: 14,745 on January 16, 2018 and 18,092 on January 16, 2018. Mr. Phillips' 89,041 phantom performance units vest on February 15, 2020. Mr. Halpin's restricted units vest as follows: 16,177 on January 5, 2018, 19,279 on January 15, 2018, 1,250 on January 16, 2018, 1,513 on January 16, 2018, 738 on June 6, 2018, 16,177 on January 5, 2019, 19,279 on January 15, 2019, 738 on June 6, 2019 and 16,178 on January 5, 2020. Mr. Halpin's phantom units vest as follows: 6,027 on January 16, 2018 and 7,396 on January 16, 2018. Mr. Halpin's 27,397 phantom performance units vest on February 15, 2020. Mr. Deneke's restricted units vest as follows: 20,189 on January 5, 2018, 22,894 on January 15, 2018, 1,812 on January 16, 2018, 2,194 on January 16, 2018, 1,475 on June 6, 2018, 20,189 on January 5, 2019, 22,894 on January 15, 2019, 1,476 on June 6, 2019, 20,189 on January 5, 2020 and 75,000 on June 30, 2020. Mr. Deneke's phantom units vest as follows: 8,110 on January 16, 2018 and 9,951 on January 16, 2018. Mr. Deneke's 33,268 phantom performance units vest on February 15, 2020. Mr. Moore's restricted units vest as follows: 9,785 on January 5, 2018, 12,146 on January 15, 2018, 1,166 on January 16, 2018, 1,412 on January 16, 2018, 2,951 on June 6, 2018, 9,785 on January 5, 2019, 12,146 on January 15, 2019, 2,951 on June 6, 2019 and 9,785 on January 5, 2020. Mr. Moore's 20,548 phantom performance units vest on February 15, 2020. Mr. Dougherty's restricted units vest as follows: 10,127 on January 5, 2018, 12,652 on January 15, 2018, 1,250 on January 16, 2018, 1,513 on January 16, 2018, 10,127 on January 5, 2019, 12,652 on January 15, 2019 and 10,128 on January 5, 2020. Mr. Dougherty's phantom units vest as follows: 7,123 on January 16, 2018 and 8,740 on January 16, 2018. Mr. Dougherty's 20,548 phantom performance units vest on February 15, 2020.

(2) Market value for CEQP units based on the NYSE closing price of $25.80 on December 29, 2017.

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Units Vested During Fiscal 2017

The following table provides information regarding restricted unit vesting during Fiscal 2017 for each of the NEOs. Value realized on upon vesting was calculated by using the NYSE closing price of Crestwood Equity Partners LP on the day immediately prior to the date that the award vested.

Name	UNIT AWARDS Number of Units Acquired On Vesting (#)	Value Realized on Vesting ($)
Robert G. Phillips	58,259	1,531,771
Robert T. Halpin	24,256	634,482
J. Heath Deneke	29,182	763,209

William H. Moore	19,236	497,349
Steven M. Dougherty	16,991	445,549

Pension Benefits during Fiscal 2017

We do not offer any pension benefits.

Non-qualified Deferred Compensation during Fiscal 2017

On November 10, 2016, our compensation committee adopted the Crestwood Nonqualified Deferred Compensation Plan (the “NQDC”). The NQDC is a nonqualified deferred compensation plan under which designated eligible participants may elect to defer compensation. Eligible participants include the executive officers, certain other senior officers and members of the Board.

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Subject to applicable tax laws, participants may elect to defer up to 50% of their base salary and up to 100% of incentive compensation earned and equity grants. In addition to elective deferrals, the NQDC permits us to make matching contributions and discretionary contributions. Participants may elect to receive payment of their vested account balances in a single cash payment or in annual installments for a period of up to five (5) years. Payments will be made on March 15 of any year at least one year after the deferral date, or upon separation from service. If a participant's employment terminates before the designated year, payment is accelerated and paid in a lump sum. Compensation deferred under the Plan represents an unsecured obligation of the Company.

Currently, none of our NEOs participate in the NQDC. Mr. Bledsoe deferred his unit awards pursuant to the Non-Qualified Deferred Compensation Plan and Mr. Somerhalder deferred his unit awards and fees pursuant to the Non-Qualified Deferred Compensation Plan.

Potential Payments upon a Change in Control or Termination during Fiscal 2017

Under the terms of the Executive Employment Agreements, if the named executive officer's employment is terminated during the initial term or a subsequent one-year renewal by Crestwood Operations without "employer cause" or the executive resigns due to "employee cause" or the named executive officer's employment with Crestwood Operations terminates as a result of death, permanent disability, or Crestwood Operations' election not to renew the Executive Employment Agreement, the executive will be entitled to receive, subject to the executive's execution of a release of claims, severance equal to two (or, in the case of Mr. Phillips, three) times the sum of the executive's base salary and average annual bonus for the prior two years, payable in equal installments over an 18-month period following termination. In addition, the named executive officer would be entitled to certain subsidized medical benefits over such 18-month period and all restricted and phantom units held by the named executive officer would vest in full.
On July 21, 2017, Mr. Deneke's Executive Employment Agreement was amended so that if Mr. Deneke's employment is terminated during the period beginning three months prior to a Change in Control and ending twelve months after a Change in Control, then the severance amount payable shall be increased to three (3) times his base salary and average annual bonus for the prior two years. On February 22, 2018, the Executive Employment Agreements for Messrs. Halpin, Moore and Dougherty were amended to add the same provision.

The following table presents information about the gross payments potentially payable to our named executive officers pursuant to the Executive Employment Agreements, assuming each such named executive officer experienced a qualifying termination of employment on December 31, 2017.

Name	Cash Severance ($)(1)	Accelerated Vesting of Restricted Units ($)(2)	Benefit Continuation ($)(3)	Total ($)
Robert G. Phillips	4,215,000	7,305,812	9,209	11,530,021
Robert T. Halpin	1,660,000	3,409,444	25,171	5,094,615
J. Heath Deneke	1,905,000	6,182,738	25,177	8,112,915
William H. Moore	1,470,000	2,133,015	25,177	3,628,192
Steven M. Dougherty	1,450,000	2,447,388	25,177	3,922,565

(1) As described above, amounts reflect cash severance payments payable upon a qualifying termination without "employer cause" or the named executive officer resigns due to "employee cause" the named executive officer will be entitled to receive pursuant to his Employment Agreements, subject to the executive's execution of a release of claims. The severance payments are equal to two (or, in the case of Mr. Phillips, three) times the sum of the named executive officer's base salary and average annual bonus for the prior two years. Mr. Deneke's cash severance would increase to $2,857,500 in the event his qualifying termination was in connection with a Change in Control. The cash severance payable to each of Messrs. Halpin, Moore and Dougherty would increase to $2,490,000, $2,205,000 and $2,175,000, respectively, in the event his qualifying termination was in connection with a Change in Control.

(2) The amounts reflected in the table above include the value of restricted units and phantom units which would be subject to accelerated vesting upon a change of control or termination without “employer cause” or the named executive officer resigns due to “employee cause.” The value reflected for the restricted units is based on the NYSE closing price of $25.80 for CEQP units on December 29, 2017.

(3) As described above, amounts reflect the value of 18 months’ subsidized medical benefit coverage provided upon a qualifying termination without “employer cause” or the named executive officer resigns due to “employee cause” the named executive officer will be entitled to receive pursuant to his Employment Agreement, subject to the executive’s execution of a release of claims.

Additionally, upon a Change in Control (as defined in the Deneke Employment Agreement) regardless of whether there is termination, the Company shall issue 125,000 restricted units to Mr. Deneke, which amount shall be fully vested on the date of issuance. The value of such restricted units, based on the NYSE closing price of $25.80 for CEQP units on December 29, 2017, is $3,225,000.

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On February 22, 2018, the Executive Employment Agreements for Messrs. Phillips, Halpin, Moore and Dougherty were amended to add a similar provision. Accordingly, if, on or before July 1, 2019, there is a Change in Control (as defined in the Omnibus Amendment), the Partnership shall issue 150,000 units to Mr. Phillips, 100,000 units to Mr. Halpin, 75,000 units to Mr. Dougherty and 75,000 unit Mr. Moore. These units shall be fully vested on their issuance date.

Director Compensation Table for Fiscal 2017

The following table sets forth the cash and non-cash compensation for Fiscal 2017 by each person who served as a non-employee director of our general partner during such time.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)(1)	Non-Qualified Deferred Comp Earnings ($)	Total ($)
Alvin Bledsoe	100,000	78,588	106	178,694
Michael France	—	78,588	—	78,588
Warren Gfeller	109,167	78,588	—	187,755
David Lumpkins(1)	100,000	78,588	—	178,588
John Sherman	80,000	78,588	—	158,588
John Somerhalder II	100,000(2)	78,588	1,302	79,890

(1) Reflects the value of restricted unit awards, calculated in accordance with ASC 718, disregarding estimated forfeitures. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 13 for a discussion of the assumptions used to determine the FASB ASC Topic 718 value of the awards. These restricted unit grants will vest on the first anniversary of grant. As of December 31, 2017, our non-employee directors held the following restricted unit awards: Mr. France, Mr. Gfeller, Mr. Lumpkins and Mr. Sherman each held 3,131 restricted units. Mr. Bledsoe and Mr. Somerhalder deferred their unit awards pursuant to the Non-Qualified Deferred Compensation Plan.

(2) Mr. Somerhalder deferred his fees pursuant to the Non-Qualified Deferred Compensation Plan.

Compensation of Directors during Fiscal 2017

Officers of our general partner who also serve as directors do not receive additional compensation. Each director receives cash compensation of $80,000 per year for serving on our board of directors. The lead director, audit committee chairperson, conflicts committee chairperson and finance committee chairperson each receive additional cash compensation of $20,000 per year and the compensation committee chairperson receives additional cash compensation of $10,000 per year. All cash compensation is paid to the non-employee directors in quarterly installments. Additionally, each non-employee director receives an annual grant of restricted units under our long-term incentive plan equal to approximately $80,000 in value that vests on the first anniversary of the date of issuance.

On December 21, 2017, our board of directors, based on the recommendation of the compensation committee, approved an increase to our director compensation program. Beginning January 1, 2018, each director will receive cash compensation of $100,000 per year for serving on our board of directors. The lead director, audit committee chairperson, conflicts committee chairperson and finance committee chairperson will continue to receive additional cash compensation of $20,000 per year and the compensation committee chairperson will continue to receive additional cash compensation of $10,000 per year. Additionally, each non-employee director will receive an annual grant of restricted units under our long-term incentive plan equal to approximately $100,000 in value that vests on the first anniversary of the date of issuance.

Each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees.

CEO Pay Ratio

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of our CEO.

We identified the median employee by examining the 2017 total taxable cash and equity compensation (again, to the extent taxed to the employee in 2017), as reflected in our payroll records as reported to the Internal Revenue Service on Form W-2, for all individuals, including our CEO, who were employed on December 31, 2017. We included all employees, whether employed on a full-time, part-time, temporary or seasonal basis. As of December 31, 2017, we employed 941 such persons. We annualized the compensation for any employees that were not employed for all of 2017 (not including seasonal or temporary

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employees), but did not make any other assumptions, adjustments, or estimates with respect to total cash compensation or equity. Since all of our employees, including our CEO, are located in the United States, we did not make any cost of living adjustments in identifying the median employee. We believe the use of total cash and equity compensation for all employees is the most appropriate compensation measure since it includes the main elements of compensation for the majority of our employees.

After identifying the median employee based on total cash and equity compensation, we calculated annual 2017 compensation for the median employee using the same methodology used to calculate the chief executive officer's total compensation as reflected in the Summary Compensation Table above. The median employee's annual 2017 compensation was as follows:

Name	Year	Salary	Bonus	Stock Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Median Employee	2017	$72,225	$500	$—	$9,734	$—	$82,459

With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2017 Summary Compensation Table included in this Annual Report, which was $6,384,820. Our 2017 ratio of chief executive officer total compensation to our median employee's total compensation is reasonably estimated to be 77:1.

Compensation Committee Interlocks and Insider Participation

The compensation committee of the board of directors of our general partner oversees the compensation of our executive officers. Warren Gfeller and Alvin Bledsoe served as the members of the compensation committee during Fiscal 2017, and neither of them was an officer or employee of our company or any of its subsidiaries during Fiscal 2017.

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

The following table sets forth certain information as of February 15, 2018, regarding the beneficial ownership of our common units by:

- each person who then beneficially owned more than 5% of such units then outstanding;
- each of the named executive officers of our general partner;
- each of the directors of our general partner; and
- all of the directors and executive officers of our general partner as a group.

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All information with respect to beneficial ownership has been furnished by the respective directors, executive officers or 5% or more unitholders, as the case may be.

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Owned	Preferred Units Beneficially Owned (2)	Percentage of Preferred Units Beneficially Owned
Magnetar Financial LLC(3)	—	—	28,859,396	41.0%
GSO COF II Holdings Partners LP(4)	—	—	20,613,860	29.0%
Crestwood Gas Services Holdings LLC(5)(6)(7)	9,985,462	14.0%	—	—
Crestwood Holdings LLC(5)(6)	7,484,449	10.5%	—	—
Oppenheimer Funds, Inc.(8)	5,658,998	7.9%	—	—
Alvin Bledsoe(9)	33,617	*	—	—
J. Heath Deneke	270,483	*	—	—
Steven M. Dougherty	165,559	*	—	—
Michael G. France	17,131	*	—	—
Warren H. Gfeller	44,832	*	—	—
Robert T. Halpin	240,383	*	—	—
Joel C. Lambert	155,510	*	—	—
David Lumpkins	34,439	*	—	—
William H. Moore	165,411	*	—	—
Robert G. Phillips	379,974	*	—	—
John J. Sherman	3,224,331	4.5%	—	—
John W. Somerhalder II(9)	15,045	*	—	—
Directors and executive officers as a group (13 persons)	4,746,715		—	—

* Indicates less than 1%

(1) Unless otherwise indicated, the contact address for all beneficial owners in this table is 811 Main Street, Suite 3400, Houston, Texas 77002.
(2) The Preferred Units convert to common units on a 1-for-10 basis as set forth in the Crestwood Equity Partners LP Partnership Agreement.
(3) Preferred Units are held in various Magnetar funds as follows: MTP Energy Master Fund Ltd. (12,106,908), MTP Energy CM LLC (6,279,407), MTP Energy Opportunities Fund LLC (3,795,187), Magnetar Structured Credit Fund, LP (1,569,708), Magnetar Constellation Fund IV LLC (1,310,603), Compass HTV LLC (961,667), Magnetar Capital Fund II LP (822,563), Blackwell Partners LLC 600,259), Magnetar Global Event Drive Fund LLC (598,021), Magnetar Andromeda Select Fund LLC (484,260), Hipparchus Fund LP (194,815) and Spectrum Opportunities Fund LP (135,998). The address for Magnetar Financial LLC is 1603 Orrington Avenue, 13th Floor, Evanston, IL 60201.
(4) Mailing address for GSO COF Holdings Partners LP is 345 Park Avenue, 31st Floor, New York, NY 10154.
(5) Crestwood Holdings LLC has shared voting power and shared investment power with Crestwood Gas Services Holdings LLC on 9,985,462 common units. Crestwood Holdings LLC, FR Crestwood Management Co-Investment LLC, Crestwood Holdings Partners LLC, FR XI CMP Holdings LLC, FR Midstream Holdings LLC, First Reserve GP XI, L.P., First Reserve GP XI, Inc., and William E. Macaulay have control over 17,469,911 common units.
(6)

Common units owned by Crestwood Gas Services Holdings LLC and Crestwood Holdings LLC are pledged as collateral under the Crestwood Holdings term loan.

(7) Does not include 438,789 subordinated units. The subordinated units may be converted to common units on a one-for-one basis upon the termination of the subordination period as set forth in the Crestwood Equity Partners LP Partnership Agreement.

(8) According to a Schedule 13G/A filed by Oppenheimer Funds, Inc., with the SEC on February 6, 2018, Oppenheimer Funds, Inc. has shared voting and dispositive power over 5,658,998 common units. The address of Oppenheimer Funds, Inc. is Two World Financial Center, 225 Liberty Street, New York, NY 10281.

(9) Includes 7,006 restricted units held in the Crestwood Nonqualified Deferred Compensation Plan.

See Part II, Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities of this report for certain information regarding securities authorized for issuance under our equity compensation plans.

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Item 13. Certain Relationships, Related Transactions and Director Independence

For a discussion of director independence, see Item 10, Directors, Executive Officers and Corporate Governance.

Transactions with Related Persons

First Reserve Joint Venture

In October 2016, Crestwood Infrastructure Holdings LLC, our wholly-owned subsidiary, and an affiliate of First Reserve formed a joint venture, Crestwood Permian Basin Holdings LLC (Crestwood Permian), to fund and own the Nautilus gathering system and other potential investments in the Delaware Permian. On June 21, 2017, the Company contributed contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico Pipeline LLC (Crestwood New Mexico), its wholly-owned subsidiary that owns our Delaware Basin assets located in Eddy County, New Mexico. These assets consist of two dry gas gathering systems (Las Animas systems) and one rich gas gathering system and processing plant (Willow Lake system). In conjunction with this contribution, First Reserve has agreed to contribute to Crestwood Permian the first $151 million of capital cost required to fund the expansion of the Delaware Basin assets, which includes a new processing plant located in Orla, Texas and associated pipelines (Orla processing plant), after which we will fund 100% of capital requirements until both parties have made an equal amount of capital contributions. We will continue to receive 100% of the available cash flow generated by the Willow Lake assets until the earlier of the Orla Plant in-service date or June 30, 2018, at which time the parties will receive distributions on a 50/50 basis.

Review, Approval or Ratification of Transactions with Related Persons

Our related person transactions policy applies to any transaction since the beginning of our fiscal year (or currently proposed transaction) in which we or any of our subsidiaries was or is to be a participant, the amount involved exceeds $120,000 and any director, director nominee, executive officer, 5% or greater unitholder (or their immediate family members) had, has or will have a direct or indirect material interest. A transaction that would be covered by this policy would include, but not be limited to, any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) or any series of similar transactions, arrangements or relationships.

Under our related person transactions policy, related person transactions may be entered into or continue only if the transaction is deemed to be “fair and reasonable” to us, in accordance with the terms of our partnership agreement. Under our partnership agreement, transactions that represent a “conflict of interest” may be approved in one of three ways and, if approved in any of those ways, will be considered “fair and reasonable” to us and the holders of our common units. The three ways enumerated in our related person transactions Policy for reaching this conclusion include:

(i) approval by the Conflicts Committee of the Board (the Conflicts Committee) under Section 7.9 of our partnership agreement (Special Approval);

(ii) approval by our Chief Executive Officer applying the criteria specified in Section 7.9 of our partnership agreement if the transaction is in the normal course of the partnership’s business and is (a) on terms no less favorable to the partnership than those generally being provided to or available from unrelated third parties or (b) fair to the partnership, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Partnership); and

(iii) approval by an independent committee of the Board (either the Audit Committee or a Special Committee) applying the criteria in Section 7.9 of our partnership agreement.

Once a transaction is approved in any of these ways, it is “fair and reasonable” and accordingly deemed (i) approved by all of our partners and (ii) not to be a breach of any fiduciary duties of general partner.

Our general partner determines in its discretion which method of approval is required depending on the circumstances. Under our partnership agreement, when determining whether a related person transaction is “fair and reasonable,” if our general partner elects to adopt a resolution or a course of action that has not received Special Approval, then our general partner may consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

- any customary or accepted industry practices and any customary or historical dealings with a particular person;

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- any applicable generally accepted accounting practices or principles; and
- such additional factors as the general partner or conflicts committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

A related person transaction that is approved by the conflicts committee is, as discussed in greater detail above, conclusively deemed to be fair and reasonable to us. Under our partnership agreement, the material facts known to our general partner or any of our affiliates regarding the transaction must be disclosed to the conflicts committee at the time the committee gives its approval. When approving a related party transaction, the conflicts committee considers all factors it considers relevant, reasonable or appropriate under the circumstances, including the relative interests of any party to the transaction, customary industry practices and generally accepted accounting principles.

Under our partnership agreement, in the absence of bad faith by the general partner, the resolution, action or terms so made, taken or provided by the general partner with respect to approval of the related party transaction will not constitute a breach of our partnership agreement or any standard of fiduciary duty.

Under our related person transactions policy, as well as under our partnership agreement, there is no obligation to take any particular conflict to the conflicts committee-empaneling that committee is entirely at the discretion of the general partner. In many ways, the decision to engage the conflicts committee can be analogized to the kinds of transactions for which a Delaware corporation might establish a special committee of independent directors. The general partner considers the specific facts and circumstances involved. Relevant facts would include:

- the nature and size of the transaction (i.e., transaction with a controlling unitholder, magnitude of consideration to be paid or received, impact of proposed transaction on the general partner and holders of common units);
- the related person’s interest in the transaction;
- whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances;
- if applicable, the availability of other sources of comparable services or products; and
- the financial costs involved, including costs for separate financial, legal and possibly other advisors at our expense.

When determining whether a related person transaction is in the normal course of our business and is (a) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (b) fair to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us), the general partner considers any facts and circumstances that it deems to be relevant, including:

- the terms of the transaction, including the aggregate value;
- the business purpose of the transaction;
- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- whether the terms of the transaction are comparable to the terms that would exist in a similar transaction with an unaffiliated third party;
- any customary or accepted industry practices;
- any applicable generally accepted accounting practices or principles; and
- such additional factors as the general partner or the conflicts committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

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Item 14. Principal Accountant Fees and Services

The Audit Committee of the Board of Directors of Crestwood Equity GP LLC approved the engagement of Ernst & Young LLP as the principal accountant to audit the partnership's financial statements as of and for the fiscal year ending December 31, 2017. The following table summarizes the fees for professional services rendered by Ernst & Young LLP for the years ended December 31, 2017 and 2016 (in millions).

	2017	2016
Audit-related fees(1)	$2.0	$1.8
All other fees(2)	0.2	0.1
Total	$2.2	$1.9

(1) Includes fees related to the performance of the annual audit and quarterly reviews (including internal control evaluation and reporting) of the consolidated financial statements of Crestwood Equity and Crestwood Midstream and its subsidiaries.

(2) Includes fees primarily associated with acquisitions, dispositions and issuances of debt and equity.

The audit committee of Crestwood Equity's general partner reviewed and approved all audit and non-audit services provided during 2017. Crestwood Midstream is a wholly-owned subsidiary of Crestwood Equity and, as such, it does not have a separate audit committee. Crestwood Equity's audit committee has adopted a pre-approval policy for audit and non-audit services. For information regarding the audit committee's pre-approval policies and procedures, see Crestwood Equity's audit committee charter on its website at www.crestwoodlp.com.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Exhibits, Financial Statements and Financial Statement Schedules:

1. Financial Statements:

See Index Page for Financial Statements

2. Financial Statement Schedules:
Schedule I: Parent Only Condensed Financial Statements
Schedule II: Valuation and Qualifying Accounts

Other financial statement schedules have been omitted because they are either not required, are immaterial or are not applicable or because equivalent information has been included in the financial statements, the notes thereto or elsewhere herein.

3. Exhibits:

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of May 5, 2015, by and among Crestwood Equity Partners LP, Crestwood Equity GP LLC, CEQP ST SUB LLC, MGP GP, LLC, Crestwood Midstream Holdings LP, Crestwood Midstream Partners LP, Crestwood Midstream GP LLC and Crestwood Gas Services GP LLC (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed May 6, 2015)
2.2	Contribution Agreement, dated as of April 20, 2016, by and between Crestwood Pipeline and Storage Northeast LLC and Con Edison Gas Pipeline and Storage Northeast, LLC (incorporated herein by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on April 22, 2016)
3.1	Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P.'s Registration Statement on Form S-1 (Registration No. 333-56976) filed on March 14, 2001)
3.2	Certificate of Correction of Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P.'s Form 10-Q filed on May 12, 2003)
3.3	Amendment to the Certificate of Limited Partnership of Crestwood Equity Partners LP (f/k/a Inergy, L.P.) (the "Partnership") dated as of October 7, 2013 (incorporated herein by reference to Exhibit 3.2 to Crestwood Equity Partners LP's Form 8-K filed on October 10, 2013)
3.4	Fifth Amended and Restated Agreement of Limited Partnership of Crestwood Equity Partners LP dated April 11, 2014 (incorporated herein by reference to Exhibit 3.1 to Crestwood Equity Partners LP's Form 8-K filed on April 11, 2014)
3.5	First Amendment to the Fifth Amended and Restated Agreement of Limited Partnership of Crestwood Equity Partners LP, dated as of September 30, 2015 (incorporated herein by reference to Exhibit 3.1 to the Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015)

3.6	Second Amendment to the Fifth Amended and Restated Agreement of Limited Partnership of Crestwood Equity Partners LP, dated as of November 8, 2017 (incorporated herein by reference to Exhibit 3.1 to Crestwood Equity Partners LP's Form 8-K filed on November 13, 2017)
3.7	Certificate of Formation of Inergy GP, LLC (incorporated herein by reference to Exhibit 3.5 to Inergy, L.P.'s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001)
3.8	Certificate of Amendment of Crestwood Equity GP LLC (f/k/a Inergy GP, LLC) dated October 7, 2013 (incorporated herein by reference to Exhibit 3.3A to Crestwood Equity Partners LP's Form 10-Q filed on November 8, 2013)
3.9	First Amended and Restated Limited Liability Company Agreement of Inergy GP, LLC dated as of September 27, 2012 (incorporated by reference to Exhibit 3.1 to Inergy, L.P.'s Form 8-K filed on September 27, 2012)

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Exhibit Number	Description
3.10	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Crestwood Equity GP LLC (f/k/a Inergy GP, LLC) entered into effective October 7, 2013 (incorporated herein by reference to Exhibit 3.4A to Crestwood Equity Partners LP's Form 10-Q filed on November 8, 2013)
3.11	Certificate of Limited Partnership of Inergy Midstream, L.P. (incorporated herein by reference to Exhibit 3.4 to Inergy Midstream, L.P.'s Form S-1/A filed on November 21, 2011)
3.12	Amendment to the Certificate of Limited Partnership of Crestwood Midstream Partners LP (f/k/a Inergy Midstream, L.P.) (incorporated herein by reference to Exhibit 3.2 to Inergy Midstream, L.P.'s Form 8-K filed on October 10, 2013)
3.13	First Amended and Restated Agreement of Limited Partnership of Inergy Midstream, L.P., dated December 21, 2011 (incorporated herein by reference to Exhibit 4.2 to Inergy Midstream, L.P.'s Form S-8 filed on December 21, 2011)
3.14	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Inergy Midstream, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy Midstream, L.P.'s Form 8-K filed on October 1, 2013)
3.15	Amendment No. 2 to the First Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP (f/k/a Inergy Midstream, L.P.) (incorporated herein by reference to Exhibit 3.1 to Crestwood Midstream Partners LP's Form 8-K filed on October 10, 2013)
3.16	Amendment No. 3 to the First Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP dated as of June 17, 2014 (incorporated herein by reference to Exhibit 3.1 to Crestwood Midstream Partners LP's Form 8-K filed on June 19, 2014)
3.17	Second Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP, dated as of September 30, 2015 (incorporated by reference to Exhibit 3.1 to Crestwood Midstream Partners LP's Form 8-K filed on October 1, 2015)
3.18	Certificate of Formation of NRGM GP, LLC (incorporated herein by reference to Exhibit 3.7 to Inergy Midstream, L.P.'s Form S-1/A filed on November 21, 2011)
3.19	Certificate of Amendment of Crestwood Midstream GP LLC (f/k/a NRGM GP, LLC) (incorporated herein by reference to Exhibit 3.37 to Crestwood Midstream Partners LP's Form S-4/A filed on October 28, 2013)
3.20	Amended and Restated Limited Liability Company Agreement of NRGM GP, LLC, dated December 21, 2011 (incorporated herein by reference to Exhibit 3.2 to Inergy Midstream, L.P.'s Form 8-K filed on December 22, 2011)
3.21	Amendment No. 1 to the Amended and Restated Limited Liability Company Agreement of Crestwood Midstream GP LLC (f/k/a NRGM GP, LLC) (incorporated herein by reference to Exhibit 3.39 to Crestwood Midstream Partners LP's Form S-4/A filed on October 28, 2013)
4.1	Specimen Unit Certificate for Common Units (incorporated herein by reference to Exhibit 4.3 to Inergy L.P.'s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001)

4.2	Indenture, dated as of March 14, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on March 15, 2017)
4.3	Supplemental Indenture dated as of June 5, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2017)
**4.4	Supplemental Indenture dated as of December 1, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee
4.5	Indenture, dated as of March 23, 2015, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Crestwood Midstream Partners LP's Form 8-K filed on March 27, 2015)

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Exhibit Number	Description
4.6	First Supplemental Indenture, dated March 4, 2016, by and among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.3 to Crestwood Midstream Partners LP's Form 8-K filed on March 7, 2016)
4.7	Supplemental Indenture, dated as of June 3, 2016, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Crestwood Midstream Partners LP's Form 10-Q filed on August 4, 2016)
4.8	Supplemental Indenture, dated as of September 30, 2016, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Crestwood Midstream Partners LP's Form 10-Q filed on November 4, 2016)
***4.9	Second Amended and Restated Limited Liability Company Agreement for Crestwood Niobrara LLC, dated December 28, 2017, between Crestwood Midstream Partners LP and CN Jackalope Holdings, LLC
**4.10	Registration Rights Agreement, dated December 28, 2017, by and among Crestwood Equity Partners LP and CN Jackalope Holdings, LLC
4.11	Registration Rights Agreement, dated as of March 14, 2017, by and among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and J.P. Morgan Securities LLC, as representative of the several initial purchasers, with respect to the 5.75% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on March 15, 2017)
4.12	Registration Rights Agreement, dated as of September 30, 2015, by and among Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015)
*10.1	Second Amended and Restated Employment Agreement, dated July 21, 2017, between Heath Deneke and Crestwood Operations LLC (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on July 25, 2017)
**10.2	Omnibus Amendment to Employment Agreements dated February 22, 2018 by and between Crestwood Operations LLC and each of Robert G. Phillips, Robert Halpin, Steven Dougherty, Joel Lambert and William H. Moore
*10.3	Employment Agreement between Robert G. Phillips and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 27, 2014)
*10.4	Employment Agreement between Joel Lambert and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on February 28, 2014)

*10.5	Employment Agreement between William H. Moore and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on March 2, 2015)
*10.6	Employment Agreement between Steven M. Dougherty and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 10-K filed on February 29, 2016)
*10.7	Amended and Restated Employee Agreement between Robert T. Halpin and Crestwood Operations LLC dated as of April 1, 2015 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on February 29, 2016)
*10.8	Crestwood Equity Partners LP Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.7 to Crestwood Equity Partners LP's Form 10-K filed on February 28, 2014)
*10.9	Form of Crestwood Equity Partners LP's Restricted Unit Award Agreement (incorporated herein by reference to Exhibit 4.12 to Crestwood Equity Partner LP's Form S-8 filed on January 16, 2015)
*10.10	Form of Crestwood Equity Partners LP's Phantom Unit Award Agreement (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 23, 2015)
*10.11	Form of Crestwood Equity Partners LP's Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 10-Q filed on May 4, 2017)

Exhibit Number	Description
*10.12	Crestwood Equity Partners Non-Qualified Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on November 15, 2016)
10.13	Amended and Restated Credit Agreement, dated as of September 30, 2015, by and among Crestwood Midstream Partners LP, as borrower, the lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 10.1 to Crestwood Midstream Partners LP's Form 8-K filed on October 1, 2015)
10.14	Amendment dated as of April 20, 2016, among Crestwood Midstream Partners LP, as borrower, certain guarantors and financial institutions party thereto, and Wells Fargo Bank, National Association, as administrative agent and collateral agent. (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on April 22, 2016)
10.15	Guaranty, dated as of April 20, 2016, made by Crestwood Equity Partners LP in favor of Con Edison Gas Pipeline and Storage Northeast, LLC (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on April 22, 2016)
10.16	Amended and Restated Limited Liability Company Agreement of Stagecoach Gas Services LLC dated as of June 3, 2016. (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on June 8, 2016)
10.17	Gas Gathering Agreement, dated as of April 6, 2016, among Cowtown Pipeline Partners L.P., as Gatherer, and BlueStone Natural Resources II, LLC, as Producer (incorporated herein by reference to Exhibit 10.3 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2016)
10.18	Gas Gathering and Processing Agreement, dated as of April 6, 2016, among BlueStone Natural Resources II, LLC, as Producer, Cowtown Pipeline Partners L.P., as Gatherer, and Cowtown Gas Processing Partners LP, as Processor (incorporated herein by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2016)
10.19	Gas Gathering Agreement, dated as of April 6, 2016, among BlueStone Natural Resources II, LLC, as Producer, and Cowtown Pipeline Partners L.P., as Gatherer (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2016)
10.20	Letter Agreement to Gathering and Processing Agreements, dated as of April 6, 2016, among Cowtown Pipeline Partners L.P., Cowtown Gas Processing Partners L.P. and BlueStone Natural Resources II, LLC(incorporated herein by reference to Exhibit 10.6 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2016)
10.21	Guarantee, dated as of February 24, 2012, by Crestwood Holdings LLC and Crestwood Midstream Partners LP, in favor of Antero Resources Appalachian Corporation (incorporated herein by reference to Exhibit 10.1 to Crestwood Midstream Partners LP's Form 8-K filed on February 28, 2012)
10.22	Gas Gathering and Compression Agreement, dated as of January 1, 2012, by and between Antero Resources Appalachian Corporation and Crestwood Marcellus Midstream LLC (incorporated herein by reference to Exhibit 10.23 to Crestwood Midstream Partners LP's Form 10-K filed on February 28, 2013)

10.23	Registration Rights Agreement, dated as of September 30, 2015, by and among Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015)
10.24	Board Representation and Standstill Agreement, dated as of September 30, 2015, by and among Crestwood Equity GP LLC, Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015)
10.25	Support Agreement, dated as of May 5, 2015, by and among Crestwood Equity Partners LP, Crestwood Midstream Partners LP and CGS GP (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on May 6, 2015)
10.26	Equity Distribution Agreement, dated August 4, 2017, by and among Crestwood Equity Partners LP and the Managers named therein (incorporated by reference to Exhibit 1.1 to Crestwood Equity Partners LP's Form 8-K filed on August 4, 2017)
**12.1	Computation of ratio of earnings to fixed charges - Crestwood Equity Partners LP
**12.2	Computation of ratio of earnings to fixed charges - Crestwood Midstream Partners LP

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Exhibit Number	Description
16.1	Letter Regarding Change in Certifying Accountant (incorporated herein by reference to Exhibit 16.1 to Inergy, L.P.'s Form 8-K/A filed on July 23, 2013)
**21.1	List of subsidiaries of Crestwood Equity Partners LP
**23.1	Consent of Ernst & Young LLP - Crestwood Equity Partners LP
**23.2	Consent of Ernst & Young LLP - Crestwood Midstream Partners LP
**31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Equity Partners LP
**31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Equity Partners LP
**31.3	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Midstream Partners LP
**31.4	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Midstream Partners LP
**32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Equity Partners LP
**32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Equity Partners LP
**32.3	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Midstream Partners LP
**32.4	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Midstream Partners LP
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contracts or compensatory plans or arrangements
** Filed herewith
***

Confidential treatment has been requested for certain portions which are omitted in the copy of the exhibit electronically filed with the SEC. The omitted information has been filed separately with the SEC pursuant to our application for confidential treatment

(b) Exhibits.

See exhibits identified above under Item 15(a)3.

(c) Financial Statement Schedules.

See financial statement schedules identified above under Item 15(a)2.

Crestwood Equity Partners LP
Crestwood Midstream Partners LP
Consolidated Financial Statements

December 31, 2017 and 2016 and each of the
Three Years in the Period Ended
December 31, 2017

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Crestwood Equity GP LLC and Unitholders of Crestwood Equity Partners LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Crestwood Equity Partners LP (the Company) as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedules listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Adoption of ASU No. 2017-04

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of measuring goodwill impairment charges as a result of adoption of the amendments to the FASB Accounting Standards Codification resulting from Accounting Standards No. 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment".

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 2013.
Houston, Texas
February 23, 2018

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Report of Independent Registered Public Accounting Firm on Internal Controls Over Financial Reporting

The Board of Directors of Crestwood Equity GP LLC and Unitholders of Crestwood Equity Partners LP

Opinion on Internal Control over Financial Reporting
We have audited Crestwood Equity Partners LP's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Crestwood Equity Partners LP (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets as of December 31, 2017 and 2016 and related consolidated statements of operations, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedules listed in the Index at Item 15(a) of the Company and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

/s/ Ernst & Young LLP
Houston, Texas
February 23, 2018

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(in millions, except unit information)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash	$1.3	$1.6
Accounts receivable, less allowance for doubtful accounts of $2.4 million and $1.9 million at December 31, 2017 and 2016	442.7	289.8
Inventory	68.4	66.0
Assets from price risk management activities	7.2	6.3
Prepaid expenses and other current assets	10.9	9.7
Total current assets	530.5	373.4
Property, plant and equipment	2,285.2	2,555.4
Less: accumulated depreciation and depletion	464.4	457.8
Property, plant and equipment, net	1,820.8	2,097.6
Intangible assets	788.8	898.6
Less: accumulated amortization	191.6	241.2
Intangible assets, net	597.2	657.4
Goodwill	147.6	199.0
Investments in unconsolidated affiliates	1,183.0	1,115.4
Other assets	5.8	6.1
Total assets	$4,284.9	$4,448.9
Liabilities and partners’ capital		
Current liabilities:		
Accounts payable	$349.4	$217.2
Accrued expenses and other liabilities	105.9	90.5
Liabilities from price risk management activities	48.9	28.6
Current portion of long-term debt	0.9	1.0
Total current liabilities	505.1	337.3
Long-term debt, less current portion	1,491.3	1,522.7
Other long-term liabilities	104.7	44.6
Deferred income taxes	3.3	5.3
Commitments and contingencies (Note 15)		
Partners’ capital:		
Crestwood Equity Partners LP partners’ capital (70,721,563 and 69,499,741 common and subordinated units issued and outstanding at December 31, 2017 and 2016)	1,393.5	1,782.0
Preferred units (71,257,445 and 66,533,415 units issued and outstanding at December 31, 2017 and 2016)	612.0	564.5
Total Crestwood Equity Partners LP partners’ capital	2,005.5	2,346.5
Interest of non-controlling partners in subsidiaries	175.0	192.5
Total partners’ capital	2,180.5	2,539.0
Total liabilities and partners’ capital	$4,284.9	$4,448.9

See accompanying notes.

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except unit and per unit data)

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Product revenues:			
Gathering and processing	$1,369.1	$825.5	$1,051.2
Marketing, supply and logistics	2,093.1	1,144.3	857.5
	3,462.2	1,969.8	1,908.7
Service revenues:			
Gathering and processing	317.3	290.7	325.9
Storage and transportation	37.2	165.3	266.3
Marketing, supply and logistics	62.4	92.1	128.0
Related party (Note 16)	1.8	2.6	3.9
	418.7	550.7	724.1
Total revenues	3,880.9	2,520.5	2,632.8
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	3,309.5	1,851.9	1,780.0
Product costs - related party (Note 16)	15.3	17.7	28.9
Service costs	49.9	55.5	74.6
Total costs of products/services sold	3,374.7	1,925.1	1,883.5
Expenses:			
Operations and maintenance	136.0	158.1	190.2
General and administrative	96.5	88.2	116.3
Depreciation, amortization and accretion	191.7	229.6	300.1
	424.2	475.9	606.6
Other operating expense:			
Loss on long-lived assets, net	(65.6)	(65.6)	(821.2)
Goodwill impairment	(38.8)	(162.6)	(1,406.3)
Loss on contingent consideration	(57.0)	—	—
Operating income (loss)	(79.4)	(108.7)	(2,084.8)

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS (continued)
(in millions, except unit and per unit data)

	Year Ended December 31,		
	2017	2016	2015
Earnings (loss) from unconsolidated affiliates, net	47.8	31.5	(60.8)
Interest and debt expense, net	(99.4)	(125.1)	(140.1)
Gain (loss) on modification/extinguishment of debt	(37.7)	10.0	(20.0)
Other income, net	1.3	0.5	0.6
Loss before income taxes	(167.4)	(191.8)	(2,305.1)
(Provision) benefit for income taxes	0.8	(0.3)	1.4
Net loss	(166.6)	(192.1)	(2,303.7)
Net income (loss) attributable to non-controlling partners	25.3	24.2	(636.8)
Net loss attributable to Crestwood Equity Partners LP	(191.9)	(216.3)	(1,666.9)
Net income attributable to preferred units	62.5	28.7	6.2
Net loss attributable to partners	$(254.4)	$(245.0)	$(1,673.1)
Common unitholders’ interest in net loss	$(254.4)	$(245.0)	$(1,673.1)
Net loss per limited partner unit:			
Basic	$(3.64)	$(3.55)	$(54.00)
Diluted	$(3.64)	$(3.55)	$(54.00)
Weighted-average limited partners’ units outstanding (in thousands):			
Basic	69,839	69,017	30,983
Dilutive units	—	—	—
Diluted	69,839	69,017	30,983

See accompanying notes.

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Net loss	$(166.6)	$(192.1)	$(2,303.7)
Change in fair value of Suburban Propane Partners, L.P. units	(0.8)	0.8	(2.7)
Comprehensive loss	(167.4)	(191.3)	(2,306.4)
Comprehensive income (loss) attributable to non-controlling partners	25.3	24.2	(636.8)
Comprehensive loss attributable to Crestwood Equity Partners LP	$(192.7)	$(215.5)	$(1,669.6)

See accompanying notes.

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in millions)

	Preferred		Partners				
	Units	Capital	Common Units	Subordinated Units	Capital	Non-Controlling Partners	Total Partners' Capital
Balance at December 31, 2014	—	$—	18.2	0.4	$776.2	$ 4,808.3	$5,584.5
Acquisition of CMLP non-controlling interest and conversion of preferred units	59.3	529.6	49.9	—	3,294.8	(3,824.4)	—
Issuance of CMLP Class A preferred units	1.4	—	—	—	—	58.8	58.8
Distributions to partners	—	—	—	—	(171.5)	(234.2)	(405.7)
Unit-based compensation charges	—	—	0.1	—	5.7	14.0	19.7
Taxes paid for unit-based compensation vesting	—	—	—	—	(1.6)	(2.1)	(3.7)
Change in fair value of Suburban Propane Partners, L.P. units	—	—	—	—	(2.7)	—	(2.7)
Other	—	—	—	—	(0.2)	(0.1)	(0.3)
Net income (loss)	—	6.2	—	—	(1,673.1)	(636.8)	(2,303.7)
Balance at December 31, 2015	60.7	535.8	68.2	0.4	2,227.6	183.5	2,946.9
Distributions to partners	5.8	—	—	—	(219.8)	(15.2)	(235.0)
Unit-based compensation charges	—	—	0.9	—	19.2	—	19.2
Taxes paid for unit-based compensation vesting	—	—	—	—	(0.8)	—	(0.8)
Change in fair value of Suburban Propane Partners, L.P. units	—	—	—	—	0.8	—	0.8
Net income (loss)	—	28.7	—	—	(245.0)	24.2	(192.1)
Balance at December 31, 2016	66.5	564.5	69.1	0.4	1,782.0	192.5	2,539.0
Distributions to partners	4.8	(15.0)	—	—	(167.6)	(15.2)	(197.8)
Unit based compensation charges	—	—	0.8	—	25.5	—	25.5
Taxes paid for unit-based compensation vesting	—	—	(0.2)	—	(5.5)	—	(5.5)
Change in fair value of Suburban Propane Partners, L.P. units	—	—	—	—	(0.8)	—	(0.8)
Issuance of common units	—	—	0.6	—	15.2	—	15.2
Redemption of non-controlling interest	—	—	—	—	—	(202.7)	(202.7)
Issuance of non-controlling interest	—	—	—	—	—	175.0	175.0
Other	—	—	—	—	(0.9)	0.1	(0.8)
Net income (loss)	—	62.5	—	—	(254.4)	25.3	(166.6)
Balance at December 31, 2017	71.3	$612.0	70.3	0.4	$1,393.5	$ 175.0	$2,180.5

See accompanying notes.

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Operating activities			
Net loss	$(166.6)	$(192.1)	$(2,303.7)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, amortization and accretion	191.7	229.6	300.1
Amortization of debt-related deferred costs	7.2	6.9	8.9
Market adjustment on interest rate swaps	—	—	(0.5)
Unit-based compensation charges	25.5	19.2	19.7
Loss on long-lived assets, net	65.6	65.6	821.2
Goodwill impairment	38.8	162.6	1,406.3
Loss on contingent consideration	57.0	—	—
(Gain) loss on modification/extinguishment of debt	37.7	(10.0)	20.0
(Earnings) loss from unconsolidated affiliates, net, adjusted for cash distributions received	(0.1)	7.6	73.6
Deferred income taxes	(2.1)	(3.1)	(3.6)
Other	0.9	1.9	0.7
Changes in operating assets and liabilities:			
Accounts receivable	(170.7)	(76.9)	119.7
Inventory	(9.9)	(22.5)	2.0
Prepaid expenses and other current assets	1.8	9.2	1.8
Accounts payable, accrued expenses and other liabilities	140.1	74.6	(128.0)
Reimbursements of property, plant and equipment	19.6	26.0	73.3
Change in price risk management activities, net	19.4	47.5	29.2
Net cash provided by operating activities	255.9	346.1	440.7
Investing activities			
Acquisitions, net of cash acquired	—	(7.2)	—
Purchases of property, plant and equipment	(188.4)	(100.7)	(182.7)
Investment in unconsolidated affiliates	(58.0)	(12.4)	(42.0)
Capital distributions from unconsolidated affiliates	59.9	14.8	9.3
Net proceeds from sale of assets	225.2	972.7	2.7
Net cash provided by (used in) investing activities	38.7	867.2	(212.7)

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CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Financing activities			
Proceeds from the issuance of long-term debt	2,838.6	1,565.3	4,261.8
Payments on long-term debt	(2,913.9)	(2,536.3)	(4,113.0)
Payments on capital leases	(2.7)	(1.9)	(2.2)
Payments for debt-related deferred costs	(1.0)	(3.5)	(17.3)
Financing fees paid for early debt redemption	—	—	(13.6)
Redemption of non-controlling interest	(202.7)	—	—
Net proceeds from issuance of non-controlling interest	175.0	—	—
Distributions to partners	(167.6)	(219.8)	(171.5)
Distributions paid to non-controlling partners	(15.2)	(15.2)	(234.2)
Distribution to preferred unit holders	(15.0)	—	—
Net proceeds from issuance of common units	15.2	—	—
Net proceeds from the issuance of Crestwood Midstream Partners LP Class A preferred units	—	—	58.8
Taxes paid for unit-based compensation vesting	(5.5)	(0.8)	(3.8)
Other	(0.1)	—	(1.3)
Net cash used in financing activities	(294.9)	(1,212.2)	(236.3)
Net change in cash	(0.3)	1.1	(8.3)
Cash at beginning of period	1.6	0.5	8.8
Cash at end of period	$1.3	$1.6	$0.5
Supplemental disclosure of cash flow information			
Cash paid during the period for interest	$95.1	$121.5	$129.0
Cash paid during the period for income taxes	$3.1	$1.4	$4.7
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$(20.4)	$(10.5)	$(14.1)

See accompanying notes.

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Crestwood Equity GP LCC
Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Crestwood Midstream Partners (the Company) as of December 31, 2017 and 2016, and the related consolidated statements of operations, partners' capital and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Adoption of ASU No. 2017-04
As discussed in Note 2 to the consolidated financial statements, the Company changed its method of measuring goodwill impairment charges as a result of adoption of the amendments to the FASB Accounting Standards Codification resulting from Accounting Standards No. 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment".

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 2013.
Houston, Texas
February 23, 2018

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash	$1.0	$1.3
Accounts receivable, less allowance for doubtful accounts of $2.4 million and $1.9 million at December 31, 2017 and 2016	442.6	289.8
Inventory	68.4	66.0
Assets from price risk management activities	7.2	6.3
Prepaid expenses and other current assets	10.9	9.7
Total current assets	530.1	373.1
Property, plant and equipment	2,615.3	2,885.5
Less: accumulated depreciation and depletion	607.8	587.1
Property, plant and equipment, net	2,007.5	2,298.4
Intangible assets	773.3	883.1
Less: accumulated amortization	177.6	230.2
Intangible assets, net	595.7	652.9
Goodwill	147.6	199.0
Investments in unconsolidated affiliates	1,183.0	1,115.4
Other assets	2.4	1.8
Total assets	$4,466.3	$4,640.6
Liabilities and partners' capital		
Current liabilities:		
Accounts payable	$346.8	$214.5
Accrued expenses and other liabilities	104.7	87.9
Liabilities from price risk management activities	48.9	28.6
Current portion of long-term debt	0.9	1.0
Total current liabilities	501.3	332.0
Long-term debt, less current portion	1,491.3	1,522.7
Other long-term liabilities	102.6	42.0
Deferred income taxes	0.7	0.7
Commitments and contingencies (Note 15)		
Partners' capital	2,195.4	2,550.7
Interest of non-controlling partners in subsidiary	175.0	192.5
Total partners' capital	2,370.4	2,743.2
Total liabilities and partners' capital	$4,466.3	$4,640.6

See accompanying notes.

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Product revenues:			
Gathering and processing	$1,369.1	$825.5	$1,051.2
Marketing, supply and logistics	2,093.1	1,144.3	857.5
	3,462.2	1,969.8	1,908.7
Service revenues:			
Gathering and processing	317.3	290.7	325.9
Storage and transportation	37.2	165.3	266.3
Marketing, supply and logistics	62.4	92.1	128.0
Related party (Note 16)	1.8	2.6	3.9
	418.7	550.7	724.1
Total revenues	3,880.9	2,520.5	2,632.8
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	3,309.5	1,851.9	1,780.0
Product costs - related party (Note 16)	15.3	17.7	28.9
Service costs	49.9	55.5	74.6
Total costs of products/services sold	3,374.7	1,925.1	1,883.5
Expenses:			
Operations and maintenance	136.0	155.0	188.7
General and administrative	93.1	85.6	105.6
Depreciation, amortization and accretion	202.7	240.5	278.5
	431.8	481.1	572.8
Other operating expense:			
Loss on long-lived assets, net	(65.6)	(65.6)	(227.8)
Goodwill impairment	(38.8)	(162.6)	(1,149.1)
Loss on contingent consideration	(57.0)	—	—
Operating loss	(87.0)	(113.9)	(1,200.4)
Earnings (loss) from unconsolidated affiliates, net	47.8	31.5	(60.8)
Interest and debt expense, net	(99.4)	(125.1)	(130.5)
Gain (loss) on modification/extinguishment of debt	(37.7)	10.0	(18.9)
Other income, net	0.8	—	—
Net loss	(175.5)	(197.5)	(1,410.6)
Net income attributable to non-controlling partners	25.3	24.2	23.1
Net loss attributable to Crestwood Midstream Partners LP	(200.8)	(221.7)	(1,433.7)
Net income attributable to Class A preferred units	—	—	23.1
Net loss attributable to partners	$(200.8)	$(221.7)	$(1,456.8)

See accompanying notes.

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in millions)

	Class A Preferred Units	Partners	Non-controlling Partners	Total Partners' Capital
Balance at December 31, 2014	$ 447.7	$4,701.0	$ 171.7	$ 5,320.4
Issuance of Class A preferred units	58.8	—	—	58.8
Exchange of CMLP Class A preferred units for CEQP preferred units	(529.6)	529.6	—	—
Distributions to partners	—	(808.2)	(11.3)	(819.5)
Unit-based compensation charges	—	18.1	—	18.1
Taxes paid for unit-based compensation vesting	—	(2.1)	—	(2.1)
Net income (loss)	23.1	(1,456.8)	23.1	(1,410.6)
Balance at December 31, 2015	—	2,981.6	183.5	3,165.1
Distributions to partners	—	(227.6)	(15.2)	(242.8)
Unit-based compensation charges	—	19.2	—	19.2
Taxes paid for unit-based compensation vesting	—	(0.8)	—	(0.8)
Net income (loss)	—	(221.7)	24.2	(197.5)
Balance at December 31, 2016	—	2,550.7	192.5	2,743.2
Distributions to partners	—	(174.0)	(15.2)	(189.2)
Unit-based compensation charges	—	25.5	—	25.5
Taxes paid for unit-based compensation vesting	—	(5.5)	—	(5.5)
Redemption of non-controlling interest	—	—	(202.7)	(202.7)
Issuance of non-controlling interest	—	—	175.0	175.0
Other	—	(0.5)	0.1	(0.4)
Net income (loss)	—	(200.8)	25.3	(175.5)
Balance at December 31, 2017	$ —	$2,195.4	$ 175.0	$ 2,370.4

See accompanying notes.

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Operating activities			
Net loss	$(175.5)	$(197.5)	$(1,410.6)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, amortization and accretion	202.7	240.5	278.5
Amortization of debt-related deferred costs	7.2	6.9	8.1
Unit-based compensation charges	25.5	19.2	18.1
Loss on long-lived assets, net	65.6	65.6	227.8
Goodwill impairment	38.8	162.6	1,149.1
Loss on contingent consideration	57.0	—	—
(Gain) loss on modification/extinguishment of debt	37.7	(10.0)	18.9
(Earnings) loss from unconsolidated affiliates, net, adjusted for cash distributions received	(0.1)	7.6	73.6
Deferred income taxes	—	0.2	(0.3)
Other	0.9	1.9	0.7
Changes in operating assets and liabilities:			
Accounts receivable	(170.5)	(76.9)	119.4
Inventory	(9.9)	(22.5)	2.1
Prepaid expenses and other current assets	1.8	7.5	3.7
Accounts payable, accrued expenses and other liabilities	142.0	75.2	(119.8)
Reimbursements of property, plant and equipment	19.6	26.0	73.3
Change in price risk management activities, net	19.4	47.5	29.2
Net cash provided by operating activities	262.2	353.8	471.8
Investing activities			
Acquisitions, net of cash acquired	—	(7.2)	—
Purchases of property, plant and equipment	(188.4)	(100.7)	(182.7)
Investment in unconsolidated affiliates	(58.0)	(12.4)	(41.8)
Capital distributions from unconsolidated affiliates	59.9	14.8	9.3
Net proceeds from sale of assets	225.2	972.7	2.7
Net cash provided by (used in) investing activities	38.7	867.2	(212.5)

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Financing activities			
Proceeds from the issuance of long-term debt	2,838.6	1,565.3	3,490.1
Payments on long-term debt	(2,913.9)	(2,536.1)	(2,960.9)
Payments on capital leases	(2.7)	(1.9)	(2.2)
Payments for debt-related deferred costs	(1.0)	(3.5)	(17.3)
Financing fees paid for early debt redemption	—	—	(13.6)
Redemption of non-controlling interest	(202.7)	—	—
Net proceeds from issuance of non-controlling interest	175.0	—	—
Distributions to partners	(189.2)	(242.8)	(819.5)
Net proceeds from issuance of Class A preferred units	—	—	58.8
Taxes paid for unit-based compensation vesting	(5.5)	(0.8)	(2.1)
Other	0.2	—	(0.1)
Net cash used in financing activities	(301.2)	(1,219.8)	(266.8)
Net change in cash	(0.3)	1.2	(7.5)
Cash at beginning of period	1.3	0.1	7.6
Cash at end of period	$1.0	$1.3	$0.1
Supplemental disclosure of cash flow information			
Cash paid during the period for interest	$95.1	$121.5	$118.2
Cash paid during the period for income taxes	$0.6	$0.7	$0.6
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$(20.4)	$(10.5)	$(14.1)

See accompanying notes.

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CRESTWOOD EQUITY PARTNERS LP
CRESTWOOD MIDSTREAM PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Organization and Description of Business

The accompanying notes to the consolidated financial statements apply to Crestwood Equity Partners LP (the Company, Crestwood Equity or CEQP) and Crestwood Midstream Partners LP (Crestwood Midstream or CMLP) unless otherwise indicated.

Organization

Crestwood Equity Partners LP. CEQP is a publicly-traded (NYSE: CEQP) Delaware limited partnership formed in March 2001. Crestwood Equity GP LLC, which is indirectly owned by Crestwood Holdings LLC (Crestwood Holdings), owns our non-economic general partnership interest. Crestwood Holdings, which is substantially owned and controlled by First Reserve Management, L.P. (First Reserve), also owns approximately 25% of Crestwood Equity's common units and all of its subordinated units.

Crestwood Midstream Partners LP. Crestwood Equity owns a 99.9% limited partnership interest in Crestwood Midstream and Crestwood Gas Services GP LLC (CGS GP), a wholly-owned subsidiary of Crestwood Equity, owns a 0.1% limited partnership interest in Crestwood Midstream. Crestwood Midstream GP LLC, a wholly-owned subsidiary of Crestwood Equity, owns the non-economic general partnership interest of Crestwood Midstream.

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The diagram below reflects a simplified version of our ownership structure as of December 31, 2017:

Unless otherwise indicated, references in this report to “we,” “us,” “our,” “ours,” “our company,” the “partnership,” the “Comp
“Crestwood Equity,” “CEQP,” and similar terms refer to either Crestwood Equity Partners LP itself or Crestwood Equity Partners LP and its consolidated subsidiaries, as the context requires. Unless otherwise indicated, references to “Crestwood Midstream” and “CMLP” refer to Crestwood Midstream Partners LP and its consolidated subsidiaries.

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Description of Business

Crestwood Equity develops, acquires, owns or controls, and operates primarily fee-based assets and operations within the energy midstream sector. We provide broad-ranging infrastructure solutions across the value chain to service premier liquids-rich natural gas and crude oil shale plays across the United States. We own and operate a diversified portfolio of crude oil and natural gas gathering, processing, storage and transportation assets and connect fundamental energy supply with energy demand across North America. Crestwood Equity is a holding company and all of its consolidated assets are owned by or through its wholly-owned subsidiary, Crestwood Midstream.

Our financial statements reflect three operating and reporting segments described below.

- Gathering and Processing: our gathering and processing (G&P) operations provide gathering and transportation services (natural gas, crude oil and produced water) and processing, treating and compression services (natural gas) to producers in unconventional shale plays and tight-gas plays in North Dakota, West Virginia, Texas, New Mexico, Wyoming and Arkansas. This segment primarily includes (i) our operations that own crude oil, rich and dry gas gathering systems, produced water gathering systems and processing plants in the Bakken, Marcellus, Barnett and Fayetteville Shale plays; and (ii) joint ventures that own rich and dry gas gathering systems and processing plants in the Delaware Permian and Powder River Basin (PRB) Niobrara Shale plays.

- Storage and Transportation: our storage and transportation (S&T) operations provide crude oil and natural gas storage and transportation services to producers, utilities and other customers. This segment primarily includes (i) our integrated crude oil loading, storage and pipeline terminal located in the heart of the Bakken and Three Forks Shale oil-producing areas in Williams County, North Dakota (the COLT Hub); and (ii) joint ventures that own regulated natural gas storage and transportation facilities in New York and Pennsylvania, natural gas storage facilities in Texas and a crude-by-rail terminal in Wyoming.

- Marketing, Supply and Logistics: our marketing, supply and logistics (MS&L) operations provide NGL and crude oil storage, marketing and transportation services to producers, refiners, marketers and other customers. This segment primarily includes (i) our fleet of rail and rolling stock, which includes our rail-to-truck NGL terminals located in Florida, Nevada, New Jersey, New York, Rhode Island and Wyoming, our truck terminal located in Utah, and our truck maintenance facilities located in Indiana, Mississippi, New Jersey and Ohio; (ii) our West Coast processing and fractionation operations located in California; (iii) our Bath and Seymour NGL storage facilities located in New York and Indiana; and (iv) our crude oil and produced water transportation assets.

Note 2 – Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements are prepared in accordance with GAAP and include the accounts of all consolidated subsidiaries after the elimination of all intercompany accounts and transactions. Certain amounts in prior periods have been reclassified to conform to the current year presentation, none of which impacted our previously reported net income, earnings per unit or partners' capital. In management's opinion, all necessary adjustments to fairly present our results of operations, financial position and cash flows for the periods presented have been made and all such adjustments are of a normal and recurring nature.

In September 2015, Crestwood Midstream merged with a wholly-owned subsidiary of CEQP, with Crestwood Midstream surviving as a wholly-owned subsidiary of CEQP (the Simplification Merger), and CEQP contributed 100% of its interest in Crestwood Operations LLC (Crestwood Operations) to Crestwood Midstream. As a result of this transaction, Crestwood Midstream controls the operating and financial decisions of Crestwood Operations. Crestwood Midstream accounted for this transaction as a reorganization of entities under common control and the accounting standards related to such transactions requires Crestwood Midstream to record the assets and liabilities of Crestwood Operations at CEQP's carrying value and retroactively adjust Crestwood Midstream's historical results to reflect the operations of Crestwood Operations as being acquired on June 19, 2013, the date in which Crestwood Midstream and Crestwood Operations came under common control. Prior to the Simplification Merger, Crestwood Equity consolidated the results of Crestwood Operations in its financial statements and as such, this transaction had no impact on its historical financial statements.

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Significant Accounting Policies

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination to consolidate or apply the equity method of accounting to an entity can also require us to evaluate whether that entity is considered a variable interest entity (VIE). This evaluation, along with the determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control or direct the policies, decisions or activities of an entity and in the case of a VIE, are not the primary beneficiary. We use the cost method of accounting where we are unable to exert significant influence over the entity.

All of our consolidated entities and equity method investments are not VIEs except for our investment in Crestwood Permian Basin Holdings LLC (Crestwood Permian). In October 2016, Crestwood Infrastructure Holdings LLC (Crestwood Infrastructure), our wholly-owned subsidiary, and an affiliate of First Reserve formed a joint venture, Crestwood Permian, to fund and own the Nautilus gathering system and other potential investments in the Delaware Permian. Crestwood Permian is a VIE because it did not have sufficient equity at risk to fund its activities at its inception (i.e., the construction of the Nautilus gathering system) without additional capital contributions from us and First Reserve, and CEQP has provided a guarantee to a third party that requires CEQP to fund 100% of the costs to build the Nautilus gathering system (which is currently estimated to cost approximately $180 million) if Crestwood Permian fails to do so. We account for our investment in Crestwood Permian as an equity method investment because we are not the primary beneficiary of the VIE as of December 31, 2017 and 2016. See Note 6 for a further discussion of our investment in Crestwood Permian.

On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico Pipeline LLC (Crestwood New Mexico), our wholly-owned subsidiary that owns our Delaware Basin assets located in Eddy County, New Mexico. This contribution was treated as a transaction between entities under common control (because of our relationship with First Reserve), and accordingly we deconsolidated Crestwood New Mexico and our investment in Crestwood Permian was increased by the historical book value of these assets of approximately $69.4 million. Crestwood New Mexico was previously included in our G&P segment. The deconsolidation of Crestwood New Mexico was not material to our consolidated financial statements as of and for the year ended December 31, 2017.

On June 3, 2016, our wholly-owned subsidiary, Crestwood Pipeline and Storage Northeast LLC (Crestwood Northeast) and Con Edison Gas Pipeline and Storage Northeast, LLC (CEGP), a wholly-owned subsidiary of Consolidated Edison, Inc. (Consolidated Edison), formed the Stagecoach Gas Services LLC (Stagecoach Gas) joint venture, to own and further develop our natural gas storage and transportation business located in the Northeast (the NE S&T assets). We contributed to the joint venture the entities owning the NE S&T assets, CEGP contributed $975 million in exchange for a 50% equity interest in Stagecoach Gas, and Stagecoach Gas distributed to us the net cash proceeds received from CEGP. The assets contributed to the joint venture were previously included in our S&T segment.

We deconsolidated the NE S&T assets as a result of the contribution of these assets to Stagecoach Gas and began accounting for our 50% equity interest in Stagecoach Gas under the equity method of accounting. The deconsolidation of our NE S&T assets resulted in a decrease of $1,127.6 million in property, plant and equipment, net, $8.5 million of intangible assets, net and $11.2 million of other assets and (liabilities), net. For a discussion of the decrease in goodwill associated with this joint venture transaction, see “Goodwill” below. See Note 6 for a further discussion of our investment in Stagecoach Gas.

Use of Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these consolidated financial statements. Actual results can differ from those estimates.

Cash

We consider all highly liquid investments with an original maturity of less than three months to be cash.

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Inventory

Inventory for our marketing, supply and logistics operations are stated at the lower of cost or market and cost is computed predominantly using the average cost method. Our inventory consists primarily of crude oil and NGLs of approximately $67.9 million and $56.7 million at December 31, 2017 and 2016.

Property, Plant and Equipment

Property, plant and equipment is recorded at is original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and interest. We capitalize major units of property replacements or improvement and expense minor items. Depreciation is computed by the straight-line method over the estimated useful lives of the assets, as follows:

	Years
Gathering systems and pipelines	15 - 20
Facilities and equipment	3 - 25
Buildings, rights-of-way and easements	1 - 40
Office furniture and fixtures	5 - 10
Vehicles	5

We depleted salt deposits included in our property, plant and equipment utilizing the unit of production method prior to their sale in December 2017.

We evaluate our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such events or changes in circumstances are present, a loss is recognized if the carrying value of the asset is in excess of the sum of the undiscounted cash flows expected to result from the use of the asset and its eventual disposition. An impairment loss is measured as the amount by which the carrying amount of the asset exceeds the fair value of the asset, which is typically based on discounted cash flow projections using assumptions as to revenues, costs and discount rates typical of third party market participants, which is a Level 3 fair value measurement.

During 2017 and 2015, we recorded the following impairments of our property, plant and equipment and we reflected these impairments in loss on long-lived assets in our consolidated statements of operations. We did not record impairments of our property, plant and equipment during the year ended December 31, 2016.

- During 2017, we incurred $81.4 million of impairments of our property, plant and equipment related to our MS&L West Coast operations, which resulted from decreasing the forecasted cash flows to be generated by those operations. The fair value of our property, plant and equipment related to our West Coast operation was $66.4 million as of December 31, 2017. Our West Coast customers experienced headwinds during 2017, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S., which caused demand for the gathering, processing and logistics services from our West Coast operations to remain relatively flat in 2017 compared to 2016. Although our West Coast operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the degree that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future.

- During 2015, we incurred $8.5 million of impairments of our property, plant and equipment related to our Granite Wash gathering and processing operations, which resulted from decreases in forecasted cash flows for those operations given that our major customer of those assets declared bankruptcy and ceased substantial drilling in the Granite Wash in the near future given current and future anticipated market conditions related to natural gas and

NGLs.

During 2015, Crestwood Equity incurred a $354.4 million impairment of its property, plant and equipment related to its Barnett gathering and processing operations, which resulted from the actions of our primary customer in the Barnett Shale, Quicksilver Resources, Inc. (Quicksilver), related to its filing for protection under Chapter 11 of the U.S. Bankruptcy Code in 2015. Crestwood Midstream did not record an impairment of its property, plant and equipment related to its gathering and processing assets in the Barnett Shale as the sum of the undiscounted cash flows expected to result from the use of the assets and their eventual disposition exceeded the carrying value of the property, plant and

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equipment by over 30%. As a result, Crestwood Midstream's property, plant and equipment exceeds Crestwood Equity's property, plant and equipment related to its gathering and processing assets in the Barnett Shale.

- During 2015, we incurred $61.9 million and $45.7 million of impairments of property, plant and equipment related to our Fayetteville and Haynesville gathering and processing operations, respectively, which resulted from decreases in forecasted cash flows for those operations given that our customers for those assets have ceased any substantial drilling in the Fayetteville and Haynesville Shales in the near future given current and future anticipated market conditions related to natural gas.

- During 2015, we incurred a $31.2 million impairment of our property, plant and equipment related to our Watkins Glen development project in our marketing, supply and logistics operations, which resulted from continued delays and uncertainties in the permitting of our proposed NGL storage facility.

At December 31, 2017, our estimates of fair value considered a number of factors, including the potential value we would receive if we sold the asset, a 12% discount rate and projected cash flows, which is a Level 3 fair value measurement. At December 31, 2015, our estimates of fair value considered a number of factors, including the potential value we would receive if we sold the asset, a 15% discount rate and projected cash flows, which is a Level 3 fair value measurement. Projected cash flows of our property, plant and equipment are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, constructions costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

Identifiable Intangible Assets

Our identifiable intangible assets consist of customer accounts, covenants not to compete, trademarks and certain revenue contracts. Customer accounts, covenants not to compete, trademarks and certain of our revenue contracts have arisen from acquisitions. We amortize certain of our revenue contracts based on the projected cash flows associated with these contracts if the projected cash flows are readily determinable, otherwise we amortize our revenue contracts on a straight-line basis. We recognize acquired intangible assets separately if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer's intent to do so.

During 2017, 2016 and 2015, we recorded the following impairments of our intangible assets and we reflected these impairments in loss on long-lived assets in our consolidated statements of operations:

- During 2017, we fully impaired $0.8 million of intangible assets related to our MS&L West Coast operations, which resulted from decreasing forecasted cash flows to be generated by those operations. Our West Coast customers experienced headwinds during 2017, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S., which caused demand for the gathering, processing and logistics services from our West Coast operations to remain relatively flat in 2017 compared to 2016. Although our West Coast operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the degree that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future.

- During 2016, we incurred a $31.4 million impairment of intangible assets related to our MS&L Trucking operations, which resulted from the impact of increased competition on our Trucking business and the loss of several key customer relationships that were acquired in 2013 to which the intangible assets related.

- During 2015, Crestwood Equity fully impaired $238.9 million of its intangible assets related to its Barnett gathering and processing operations, which resulted from the actions of our primary customer in the Barnett Shale, Quicksilver, related to filing for protection under Chapter 11 of the U.S. Bankruptcy Code in 2015.

- During 2015, we fully impaired $70.9 million and $6.0 million of intangible assets related to our Fayetteville and Haynesville gathering and processing operations, respectively, which resulted from decreases in forecasted cash flows for those operations given that our customers for those assets have ceased any substantial drilling in the Fayetteville and Haynesville Shales in the near future given current and future anticipated market conditions related to natural gas.

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At December 31, 2016, our estimates of fair value considered a number of factors, including the potential value we would receive if we sold the asset, a 19% discount rate and projected cash flows, which is a Level 3 fair value measurement. At December 31, 2015, our estimates of fair value considered a number of factors, including the potential value we would receive if we sold the asset, a 15% discount rate and projected cash flows, which is a Level 3 fair value measurement. Projected cash flows of our intangible assets are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, construction costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

Certain intangible assets are amortized on a straight-line basis over their estimated economic lives, as follows:

	Weighted-Average Life (years)
Customer accounts and revenue contracts	20
Trademarks	6 - 8

Assets Held for Sale

We classify assets (or groups of assets) to be disposed of as held for sale when specific criteria have been met. Assets classified as held for sale are recorded at the lower of the carrying value or the estimated fair value less cost to sell of those assets. The fair value is based on the consideration to be received, which is a Level 3 fair value measurement. We cease depreciation and amortization of the assets in the period they are considered held for sale. We classified approximately $3.0 million of property, plant and equipment related to our Marcellus gathering and processing assets as assets held for sale (which is included in prepaid expenses and other current assets) on our consolidated balance sheet at their fair value at December 31, 2017. In addition, we recorded a loss on long-lived assets of approximately $2.5 million during the year ended December 31, 2017 related to these assets. The sale is contingent upon customary approvals and satisfaction of certain other closing conditions, which we believe is probable at December 31, 2017.

Goodwill

Our goodwill represents the excess of the amount we paid for a business over the fair value of the net identifiable assets acquired. We evaluate goodwill for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount. This evaluation requires us to compare the fair value of each of our reporting units to its carrying value (including goodwill). If the fair value exceeds the carrying amount, goodwill of the reporting unit is not considered impaired.

We estimate the fair value of our reporting units based on a number of factors, including discount rates, projected cash flows and the potential value we would receive if we sold the reporting unit. We also compare the total fair value of our reporting units to our overall enterprise value, which considers the market value for our common and preferred units. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our reporting units (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates. If the assumptions embodied in the projections prove inaccurate, we could incur a future impairment charge. In addition, the use of the income approach to determine the fair value of our reporting units (see further discussion of the use of the income approach below) could result in a different fair value if we had utilized a market approach, or a combination thereof.

We acquired substantially all of our reporting units in 2013, 2012 and 2011, which required us to record the assets, liabilities and goodwill of each of those reporting units at fair value on the date they were acquired. As a result, any level of decrease in the forecasted cash flows of these businesses or increases in the discount rates utilized to value those businesses from their respective acquisition dates would likely result in the fair value of the reporting unit falling below the carrying value of the reporting unit, and could result in an assessment of whether that reporting unit's goodwill is impaired.

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Current commodity prices are significantly lower compared to commodity prices during 2014, and that decrease has adversely impacted forecasted cash flows, discount rates and stock/unit prices for most companies in the midstream industry, including us. As a result, we recorded goodwill impairments on several of our reporting units during 2017, 2016 and 2015. At December 31, 2017, our accumulated goodwill impairments at CEQP and CMLP were approximately $1,656.5 million and $1,399.3 million, respectively. During 2017, we adopted the provisions of ASU 2017-04, Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment, which allows companies to apply a single test to determine if goodwill is impaired and the amount of any impairment, which is reflected in our 2017 goodwill impairments. The following table summarizes the goodwill of our various reporting units (in millions):

	Goodwill Impairments during the Year Ended December 31, 2015	Goodwill at January 1, 2016	Goodwill Impairments during the Year Ended December 31, 2016	Other	Goodwill at December 31, 2016	Impact of Sale of US Salt	Goodwill Impairments during the Year Ended December 31, 2017	Goodwill at December 31, 2017
G&P								
Fayetteville	$ 72.5	$—	$ —	$—	$ —	$—	$ —	$ —
Marcellus	—	8.6	8.6	—	—	—	—	—
Arrow	—	45.9	—	—	45.9	—	—	45.9
S&T								
Northeast Storage and Transportation	—	726.3	—	(726.3)[1]	—	—	—	—
COLT	623.4	44.9	44.9	—	—	—	—	—
MS&L								—
West Coast	85.9	—	—	2.4 [2]	2.4	—	2.4	—
Supply and Logistics	99.0	167.2	65.5	—	101.7	—	—	101.7
Storage and Terminals	53.7	50.5	14.1	—	36.4	—	36.4	—
US Salt	—	12.6	—	—	12.6	(12.6)[3]	—	—
Trucking	148.4	29.5	29.5	—	—	—	—	—
Watkins Glen	66.2	—	—	—	—	—	—	—
Total CMLP	$ 1,149.1	$1,085.5	$ 162.6	$(723.9)	$ 199.0	$(12.6)	$ 38.8	$ 147.6
Barnett (G&P)	257.2	—	—	—	—	—	—	—
Total CEQP	$ 1,406.3	$1,085.5	$ 162.6	$(723.9)	$ 199.0	$(12.6)	$ 38.8	$ 147.6

(1) Reflects impact of the deconsolidation of our NE S&T assets in June 2016.

(2) In December 2016, we acquired four NGL terminals for our MS&L segment for approximately $7.2 million with total goodwill of approximately $2.4 million. This acquisition was not material to our consolidated financial statements as of and for the year ended December 31, 2016.

(3) In December 2017, we sold 100% of our equity interests in US Salt to an affiliate of Kissner Group Holdings LP.

The goodwill impairments recorded during 2017 related to our MS&L West Coast and Storage and Terminals operations. The goodwill impairment related to our MS&L West Coast operations resulted from decreasing forecasted cash flows to be generated by those operations. Our West Coast customers experienced headwinds during 2017, with both producers and refineries located in the Western U.S. experiencing regulatory challenges and an inflow of NGLs from the Eastern U.S., which caused demand for gathering, processing and logistics services from our West Coast operations to remain relatively flat over the past several years. Although our West Coast operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the degree that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future. The goodwill impairment related to our MS&L Storage and Terminals operations resulted from decreasing forecasted cash flows to be generated by those operations. During 2017, we experienced NGL market headwinds in the Northeast with NGL exports and other market dynamics causing price differentials to narrow between purchasing NGLs in the summer (which are then stored in our NGL facilities) and selling NGLs in the winter. These dynamics also caused the rates that we are able to charge for storing NGLs in our facilities to decline from their historical levels. Although our MS&L Storage and Terminals operations' results have been relatively consistent over the past several years, these operations have not experienced growth as fast or to the decrease that we expected when we merged with Inergy, LP in 2013, and during 2017, we revised our forecasted cash flows to reflect current market dynamics, which we believe will continue for the foreseeable future. We utilized the income approach to determine the fair value of our reporting units given the limited availability of comparable market-

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based transactions during 2017, and we utilized discount rates ranging from 10% to 12% in applying the income approach to determine the fair value of our reporting units with goodwill as of December 31, 2017, which is a Level 3 fair value measurement.

The goodwill impairments recorded during 2016 related to our G&P Marcellus operations, our MS&L Supply and Logistics and Storage and Terminals operations, our S&T COLT operations and our MS&L Trucking operations. The 2016 goodwill impairments on our Marcellus, Supply and Logistics, and Storage and Terminals operations primarily resulted from increasing the discount rates utilized in determining the fair value of those reporting units considering the significant decrease in the market price of our common units during the first quarter of 2016 and the continued decrease in commodity prices and its impact on the midstream industry and our customers. The 2016 goodwill impairments on our COLT and Trucking operations also resulted from those factors, but in addition they were impacted by (i) the expiration of two key crude-by-rail loading contracts during the fourth quarter of 2016, and the impact of those expirations on our projected future cash flows from our COLT operations; and (ii) the continued impact of increased competition on our Trucking business, a change in management in late 2016, and the planned downsizing of the excess capacity in our trucking fleet and operations and the impact that these had on our projected future cash flows from our Trucking operations. Although certain of these operations experienced increases in their operating results from 2013 to 2016, we decreased the cash flow forecasts for those businesses from the expectations when they were acquired in 2012 and 2013 based on our current assessment of the impact that the prolonged low commodity price environment is expected to have on demand for future services provided by those operations. We utilized the income approach to determine the fair value of our reporting units given the limited availability of comparable market-based transactions during 2016, and we utilized discount rates ranging from 10% to 19% in applying the income approach to determine the fair value of our reporting units with goodwill as of December 31, 2016, which is a Level 3 fair value measurement.

The goodwill impairments recorded during 2015 primarily resulted from decreasing forecasted cash flows and increasing the discount rates utilized in determining the fair value of the reporting units considering the continued decrease in commodity prices and its impact on the midstream industry and our customers. We utilized the income approach to determine the fair value of our reporting units given the limited availability of comparable market-based transactions during 2015, and we utilized discount rates ranging from 9% to 12% in 2015 in applying the income approach to determine the fair value of our reporting units with goodwill as of December 31, 2015.

In addition to the goodwill impairments recorded by Crestwood Midstream as reflected in the table above, Crestwood Equity recorded a goodwill impairment of its Barnett reporting unit of approximately $257.2 million in 2015. The impairment primarily resulted from increasing the discount rate utilized in determining the fair value of the reporting unit, considering the actions of its primary customer in the Barnett Shale during 2015, Quicksilver, related to its filing for protection under Chapter 11 of the U.S. Bankruptcy Code in March 2015.

Investment in Unconsolidated Affiliates

Equity method investments in which we exercise significant influence, but do not control and are not the primary beneficiary, are accounted for using the equity method of accounting. Differences in the basis of investments and the separate net asset values of the investees, if any, are amortized into net income or loss over the remaining useful lives of the underlying assets and liabilities, except for the excess related to goodwill. We evaluate our equity method investments for impairment when events or circumstances indicate that the carrying value of the equity method investment may be impaired and that impairment is other than temporary. If an event occurs, we evaluate the recoverability of our carrying value based on the fair value of the investment. If an impairment is indicated, or if we decide to sell an investment in unconsolidated affiliate, we adjust the carrying values of the asset downward, if necessary, to their estimated fair values.

During 2015, we recorded a $51.4 million and $23.4 million impairment of our Jackalope Gas Gathering Services, L.L.C. (Jackalope) and Powder River Basin Industrial Complex, LLC (PRBIC) equity method investments, respectively, as a result of decreasing forecasted cash flows and increasing the discount rates utilized in determining the fair value of the equity method investments considering the continued decrease in commodity prices and its impact on the midstream industry and our equity method investments' customers, which is a Level 3 fair value measurement. We did not record impairments of our equity method investments during the years ended December 31, 2017 and 2016.

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We estimated the fair value of our equity method investments at December 31, 2015 based on projected cash flows, a 15.5% discount rate and the potential value we would receive if we sold the equity method investment. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our equity method investments (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our equity method investments' customers, such as future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

Asset Retirement Obligations

An asset retirement obligation (ARO) is an estimated liability for the cost to retire a tangible asset. We record a liability for legal or contractual obligations to retire our long-lived assets associated with our facilities and right-of-way contracts we hold. We record a liability in the period the obligation is incurred and estimable. An ARO is initially recorded at its estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the asset to which that liability relates. An ongoing expense is recognized for changes in the fair value of the liability as a result of the passage of time, which we record as depreciation, amortization and accretion expense on our consolidated statements of operations. The fair value of certain AROs could not be determined as the settlement dates (or range of dates) associated with these assets were not estimable. At December 31, 2017 and 2016, our AROs were reflected in other long-term liabilities on our consolidated balance sheets. See Note 5 for a further discussion of our AROs.

Deferred Financing Costs

Deferred financing costs represent costs associated with obtaining long-term financing and are amortized over the term of the
related debt using a method which approximates the effective interest method and has a weighted average life of five years. At December 31, 2017 and 2016, our net deferred financing costs were reflected as a reduction of long-term debt on our consolidated balance sheets.

Revenue Recognition

We gather, process, treat, compress, store, transport and sell various commodities (including crude oil, natural gas, NGLs and water) pursuant to fixed-fee and percent-of-proceeds contracts. Under certain of those contracts in our G&P operations and our MS&L operations, we take title to the underlying commodity. We classify the revenues associated with the products to which we take title as product revenues and all other revenues as service revenues in our consolidated statement of operations.

We recognize revenues for these services and products when all of the following criteria are met:

• services have been rendered or products delivered or sold;
• persuasive evidence of an exchange arrangement exists;
• the price for services is fixed or determinable; and
• collectability is reasonably assured.

We record deferred revenue when we receive amounts from our customers but have not met the criteria listed above. We recognize deferred revenue in our consolidated statements of operations when the criteria has been met and all services have been rendered. At December 31, 2017 and 2016, we had deferred revenue of approximately $0.6 million and $7.5 million, which is reflected in accrued expenses and other liabilities on our consolidated balance sheets.

Credit Risk and Concentrations

Inherent in our contractual portfolio are certain credit risks. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing credit risk and have established control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate.

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Income Taxes

Crestwood Equity is a master limited partnership and Crestwood Midstream is a limited partnership. Partnerships are generally not subject to federal income tax, although publicly-traded partnerships are treated as corporations for federal income tax purposes and therefore are subject to federal income tax, unless the partnership generates at least 90% of its gross income from qualifying sources. If the qualifying income requirement is satisfied, the publicly-traded partnership will be treated as a partnership for federal income tax purposes. We satisfy the qualifying income requirement and are treated as a partnership for federal and state income tax purposes. Our consolidated earnings are included in the federal and state income tax returns of our partners. However, legislation in certain states allows for taxation of partnerships, and as such, certain state taxes have been included in our accompanying financial statements as income taxes due to the nature of the tax in those particular states as discussed below. In addition, federal and state income taxes are provided on the earnings of the subsidiaries incorporated as taxable entities. We are required to recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial reporting and tax basis of assets and liabilities using expected rates in effect for the year in which the differences are expected to reverse.

We are responsible for the Texas Margin tax computed on the Texas franchise tax returns. The margin tax qualifies as an income tax under GAAP, which requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis attributable to such tax.

Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and the financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

Environmental Costs and Other Contingencies

We recognize liabilities for environmental and other contingencies when there is an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of range is accrued.

We record liabilities for environmental contingencies at their undiscounted amounts on our consolidated balance sheets as accrued expenses and other liabilities when environmental assessments indicate that remediation efforts are probable and costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts and presently enacted laws and regulations, taking into consideration the likely effects of other societal and economic factors. These estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and recognize a current period charge in operations and maintenance expenses when clean-up efforts do not benefit future periods.

We evaluate potential recoveries of amounts from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our consolidated balance sheet.

Price Risk Management Activities

We utilize certain derivative financial instruments to (i) manage our exposure to commodity price risk, specifically, the related change in the fair value of inventory, as well as the variability of cash flows related to forecasted transactions; (ii) ensure the availability of adequate physical supply of commodity; and (iii) manage our exposure to the interest rate risk associated with fixed and variable rate borrowings. We record all derivative instruments on the balance sheet at their fair values as either assets or liabilities measured at fair value. Changes in the fair value of these derivative financial instruments are recorded through current earnings.

We did not have any derivatives identified as fair value hedges or cash flow hedges for accounting purposes during the years ended December 31, 2017, 2016 or 2015.

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Unit-Based Compensation

Long-term incentive awards are granted under the Crestwood Equity incentive plan. Unit-based compensation awards consist of restricted units that are valued at the closing market price of CEQP's common units on the date of grant, which reflects the fair value of such awards. For those awards that are settled in cash, the associated liability is remeasured at every balance sheet date through settlement, such that the vested portion of the liability is adjusted to reflect its revised fair value through compensation expense. We generally recognize the expense associated with the award over the vesting period on a straight line basis. Effective January 1, 2017, we adopted the provisions of ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which simplifies several aspects of the accounting for share-based payment award transactions, including the classification of awards as either equity or liabilities and the presentation on the statement of cash flows. The adoption of this accounting standard did not have a material impact on our consolidated financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2017, the following accounting standards had not yet been adopted by us:

Revenue. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance. We utilized the modified retrospective method to adopt the provisions of this standard effective January 1, 2018. Upon adoption of the standard we began classifying certain capital expenditure reimbursements from our customers as deferred revenue rather than as reductions of property, plant and equipment in our consolidated financial statements. We reclassified approximately $69.1 million of these net reimbursements to net deferred revenue on January 1, 2018, which primarily resulted in approximately $20.0 million cumulative effect of accounting change being recorded as an increase to partners' capital on January 1, 2018. In addition, the standard requires us to begin classifying service revenues on certain of our gathering and processing contracts as reductions of costs of product sold prospectively beginning January 1, 2018.

Leases. In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which revises the accounting for leases by requiring certain leases to be recognized as assets and liabilities on the balance sheet, and requiring companies to disclose additional information about their leasing arrangements. We expect to adopt the provisions of this standard effective January 1, 2019 and are currently evaluating the impact that this standard will have on our consolidated financial statements.

Cash Flows. In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments, which clarifies how certain cash receipts and cash payments are presented and classified in the statement of cash flows. We adopted the provisions of this standard effective January 1, 2018, and the adoption of this standard did not have a material impact on our consolidated financial statements.

Note 3 – Divestiture

In December 2017, we sold 100% of our equity interests in US Salt, a solution-mining and salt production company located on the shores of Seneca Lake near Watkins Glen in Schuyler County, New York, to an affiliate of Kissner Group Holdings LP, for net proceeds of approximately $223.6 million. The sale of US Salt resulted in a decrease of $157.4 million of property, plant and equipment, net, $12.6 million of goodwill, $5.8 million of intangible assets and $14.2 million of other assets and liabilities, net. During the year ended December 31, 2017, we recognized a gain of approximately $33.6 million from the sale, which was included in gain (loss) on long-lived assets in our consolidated statement of operations. As part of the US Salt divestiture, we retained all surface and sub-surface rights necessary to place the Watkins Glen NGL storage development project into service once we receive all required regulatory approvals. US Salt was previously included in our MS&L segment.

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Note 4 – Certain Balance Sheet Information

Property, Plant and Equipment

Property, plant and equipment of the following at December 31, 2017 and 2016 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2017	2016	2017	2016
Gathering systems and pipelines and related assets	$678.0	$639.4	$820.9	$782.3
Facilities and equipment	1,141.4	1,328.3	1,326.5	1,513.4
Buildings, land, rights-of-way, storage rights and easements	319.1	315.4	322.8	319.1
Vehicles	37.3	45.7	35.5	44.0
Construction in process	87.5	85.9	87.5	85.9
Salt deposits	—	120.5	—	120.5
Office furniture and fixtures	21.9	20.2	22.1	20.3
	2,285.2	2,555.4	2,615.3	2,885.5
Less: accumulated depreciation and depletion	464.4	457.8	607.8	587.1
Total property, plant and equipment, net	$1,820.8	$2,097.6	$2,007.5	$2,298.4

Depreciation. CEQP's depreciation expense totaled $135.9 million, $154.8 million and $195.1 million for the years ended December 31, 2017, 2016 and 2015. CMLP's depreciation expense totaled $150.0 million, $168.9 million and $186.7 million for the years ended December 31, 2017, 2016 and 2015. Depletion expense at both CEQP and CMLP totaled $0.7 million for each of the years ended December 31, 2017, 2016 and 2015.

Capitalized Interest. During the years ended December 31, 2017, 2016 and 2015, CEQP and CMLP capitalized interest of $2.9 million, $0.7 million and $2.5 million related to certain expansion projects.

Gain (Loss) on Long-Lived Assets. During the year ended December 31, 2017, we recorded a gain of approximately $33.6 million on the sale of our 100% interest in US Salt. In addition, we recorded a loss of approximately $14.4 million during the year ended December 31, 2017, related to the retirement and/or disposition of certain of our Marcellus and Arrow gathering and processing assets.

Intangible Assets

Intangible assets consisted of the following at December 31, 2017 and 2016 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2017	2016	2017	2016
Customer accounts	$438.9	$541.9	$438.9	$541.9
Covenants not to compete	—	1.0	—	1.0
Gas gathering, compression and processing contracts	325.2	325.2	325.2	325.2
Trademarks	24.7	30.5	9.2	15.0
	788.8	898.6	773.3	883.1
Less: accumulated amortization	191.6	241.2	177.6	230.2
Total intangible assets, net	$597.2	$657.4	$595.7	$652.9

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The following table summarizes total accumulated amortization of our intangible assets at December 31, 2017 and 2016 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2017	2016	2017	2016
Customer accounts	$89.8	$162.4	$89.8	$162.4
Gas gathering, compression and processing contracts	82.0	63.2	82.0	63.2
Trademarks	19.8	15.6	5.8	4.6
Total accumulated amortization	$191.6	$241.2	$177.6	$230.2

Crestwood Equity’s amortization expense related to its intangible assets for the years ended December 31, 2017, 2016 and 2015, was approximately $53.7 million, $72.5 million and $102.8 million. Crestwood Midstream’s amortization expense related to its intangible assets for the years ended December 31, 2017, 2016 and 2015 was approximately $50.6 million, $69.3 million and $89.6 million.

Estimated amortization of our intangible assets for the next five years is as follows (in millions):

	CEQP	CMLP
Year Ending December 31,		
2018	$43.4	$42.0
2019	41.7	41.7
2020	41.7	41.7
2021	41.7	41.7
2022	41.7	41.7

Accrued Expenses and Other Liabilities

Accrued expenses and other liabilities consisted of the following at December 31, 2017 and 2016 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2017	2016	2017	2016
Accrued expenses	$56.6	$46.5	$55.5	$45.1
Accrued property taxes	4.8	4.2	4.8	4.2
Accrued natural gas purchases	—	4.9	—	4.9
Income tax payable	0.3	1.6	0.3	0.4
Interest payable	20.3	22.8	20.3	22.8
Accrued additions to property, plant and equipment	22.3	1.7	22.2	1.7
Capital leases	1.0	1.3	1.0	1.3
Deferred revenue	0.6	7.5	0.6	7.5
Total accrued expenses and other liabilities	$105.9	$90.5	$104.7	$87.9

Note 5 - Asset Retirement Obligations

We have legal obligations associated with our facilities and right-of-way contracts we hold. Where we can reasonably estimate the asset retirement obligation, we accrue a liability based on an estimate of the timing and amount of settlement. We record changes in these estimates based on changes in the expected amount and timing of payments to settle our obligations.

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The following table presents the changes in the net asset retirement obligations for the years ended December 31, 2017 and 2016 (in millions):

	December 31,	
	2017	2016
Net asset retirement obligation at January 1	$27.8	$26.4
Liabilities incurred	—	1.0
Liabilities settled	(1.2)	(1.2)
Accretion expense	1.4	1.6
Change in estimate	(0.5)	—
Net asset retirement obligation at December 31	$27.5	$27.8

We did not have any material assets that were legally restricted for use in settling asset retirement obligations as of December 31, 2017 and 2016.

Note 6 - Investments in Unconsolidated Affiliates

Net Investments and Earnings (Loss)

Our net investments in and earnings (loss) from our unconsolidated affiliates are as follows (in millions, unless otherwise stated):

	Ownership Percentage	Investment		Earnings (Loss) from Unconsolidated Affiliates		
	December 31,	December 31,		Year Ended December 31,		
	2017	2017	2016	2017	2016	2015
Stagecoach Gas Services LLC	50.00 %	$849.8	$871.0	$25.3	$15.9	$—
Jackalope Gas Gathering Services, L.L.C.	50.00 % (1)	184.9	197.2	10.5	20.8	(43.4) (3)
Crestwood Permian Basin Holdings LLC	50.00 %	102.0	(0.5)	8.4	(0.5)	—
Tres Palacios Holdings LLC	50.01 %	37.8	39.0	2.2	(0.3)	2.5
Powder River Basin Industrial Complex, LLC (2)	50.01 %	8.5	8.7	1.4	(4.4) (3)	(19.9) (3)
Total		$1,183.0	$1,115.4	$47.8	$31.5	$(60.8)

(1) Excludes non-controlling interest related to our investment in Jackalope. See Note 12 for a further discussion of our non-controlling interest related to our investment in Jackalope.

(2) During the year ended December 31, 2015, we recorded additional equity earnings of approximately $3.2 million related to a gain associated with the adjustment of our member's capital account by our equity investee.

(3) During the year ended December 31, 2016, we recorded a reduction of our equity earnings from PRBIC of approximately $5.8 million related to impairments recorded by our equity investee. During the year ended December 31, 2015, we recorded impairments of our PRBIC and Jackalope equity investments of approximately $23.4 million and $51.4 million. For a further discussion of these impairments, see Note 2.

Description of Investments

Crestwood Permian Basin Holdings LLC

In October 2016, Crestwood Infrastructure, our wholly-owned subsidiary, and an affiliate of First Reserve formed a joint venture, Crestwood Permian, to fund and own the Nautilus gathering system (described below) and other potential investments in the Delaware Permian. As part of this transaction, we transferred to the Crestwood Permian joint venture 100% of the equity interest of Crestwood Permian Basin LLC (Crestwood Permian Basin), which owns the Nautilus gathering system. We manage and account for our 50% ownership interest in Crestwood Permian, which is a VIE, under the equity method of accounting as we exercise significant influence, but do not control Crestwood Permian and we are not its primary beneficiary due to First Reserve's rights to exercise control over the entity.

Crestwood Permian Basin has a long-term agreement with SWEPI LP (SWEPI), a subsidiary of Royal Dutch Shell plc, to construct, own and operate a natural gas gathering system (the Nautilus gathering system) in SWEPI's operated position in the

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Delaware Permian. SWEPI has dedicated to Crestwood Permian Basin approximately 100,000 acres and gathering rights for SWEPI's gas production across a large acreage position in Loving, Reeves and Ward Counties, Texas. Crestwood Permian Basin provides gathering, dehydration, compression and liquids handling services to SWEPI on a fixed-fee basis. In conjunction with the Crestwood Permian Basin's agreement with SWEPI, Crestwood Permian granted Shell Midstream Partners L.P. (Shell Midstream), a subsidiary of Royal Dutch Shell plc, an option to purchase up to 50% equity interest in Crestwood Permian Basin. In October 2017, Shell Midstream exercised its option and purchased a 50% equity interest in Crestwood Permian Basin from Crestwood Permian for approximately $37.9 million in cash. Crestwood Permian distributed to us approximately $18.9 million of the cash proceeds received.

CEQP issued a guarantee in conjunction with the Crestwood Permian Basin gas gathering agreement with SWEPI described above, under which CEQP has agreed to fund 100% of the costs to build the Nautilus gathering system (which is currently estimated to cost $180 million, of which approximately $84.3 million has been spent through December 31, 2017) if Crestwood Permian fails to do so. We do not believe this guarantee is probable of resulting in future losses based on our assessment of the nature of the guarantee, the financial condition of the guaranteed party and the period of time that the guarantee has been outstanding, and as a result, we have not recorded a liability on our balance sheet at December 31, 2017 and 2016.

On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico, our wholly-owned subsidiary that owns our Delaware Basin assets located in Eddy County, New Mexico. This contribution was treated as a transaction between entities under common control (because of our relationship with First Reserve), and accordingly we deconsolidated Crestwood New Mexico and our investment in Crestwood Permian was increased by the historical book value of these assets of approximately $69.4 million. In conjunction with this contribution, First Reserve has agreed to contribute to Crestwood Permian the first $151 million of capital costs required to fund the expansion of the Delaware Basin assets, which includes a new processing plant located in Orla, Texas and associated pipelines (Orla processing plant).

Stagecoach Gas Services LLC

On June 3, 2016, Crestwood Northeast and CEGP formed Stagecoach Gas to own and further develop our NE S&T assets. During 2016, we contributed to Stagecoach Gas the entities owning the NE S&T assets. Additionally, CEGP contributed $975 million to Stagecoach Gas in exchange for a 50% equity interest in Stagecoach Gas, and Stagecoach Gas distributed to us the cash proceeds received (net of approximately $3 million of cash transferred to the joint venture) from CEGP. We deconsolidated the NE S&T assets as a result of this transaction discussed above and began accounting for our 50% equity interest in Stagecoach Gas under the equity method of accounting. We recognized a loss of approximately $32.4 million on the deconsolidation of the NE S&T assets.

Pursuant to the Stagecoach Gas limited liability company agreement, we may be required to make payments of up to $57 million to CEGP after December 31, 2020 if certain criteria are not met by Stagecoach Gas by December 31, 2020, including achieving certain performance targets on growth capital projects. These growth capital projects depend on the construction of other third-party expansion projects, and during 2017, those third-party projects experienced regulatory and other delays that caused Stagecoach Gas to delay its growth capital projects. Although Stagecoach Gas anticipates that these growth capital projects will be constructed in the future, it does not expect that these projects will produce meaningful operating results prior to December 31, 2020. As a result, at December 31, 2017, we recorded a liability of $57 million for this obligation, which is reflected in other long-term liabilities on our consolidated balance sheet and in loss on contingent consideration in our consolidated income statement for the year ended December 31, 2017.

Jackalope Gas Gathering Services, L.L.C.

Crestwood Niobrara LLC (Crestwood Niobrara), our consolidated subsidiary, owns a 50% ownership interest in Jackalope which we account for under the equity method of accounting. Williams Partners LP operates and owns the remaining 50% interest in Jackalope. Crestwood Niobrara manages the commercial operations of the Jackalope system.

Tres Palacios Holdings LLC

Crestwood Midstream owns a 50.01% ownership interest in Tres Palacios Holdings LLC (Tres Holdings) and is the operator of Tres Palacios Gas Storage LLC (Tres Palacios) and its assets. Brookfield Infrastructure Group owns the remaining 49.99% ownership interest in Tres Holdings. We account for our investment in Tres Holdings under the equity method of accounting.

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Powder River Basin Industrial Complex, LLC

Crestwood Crude Logistics LLC (Crude Logistics), our consolidated subsidiary, owns a 50% ownership interest in PRBIC which we account for under the equity method of accounting. Twin Eagle Powder River Basin, LLC owns the remaining 50% ownership interest in PRBIC.

Summarized Financial Information of Unconsolidated Affiliates

Below is summarized financial information for our significant unconsolidated affiliates (in millions; amounts represent 100% of unconsolidated affiliate information):

Financial Position Data

	December 31, 2017					2016				
	Current Assets	Non-Current Assets	Current Liabilities	Non-Current Liabilities	Members' Equity	Current Assets	Non-Current Assets	Current Liabilities	Non-Current Liabilities	Members' Equity
Stagecoach[1]	$55.1	$ 1,765.4	$ 7.0	$ 1.4	$1,812.1	$57.0	$ 1,807.6	$ 6.0	$ 4.1	$1,854.5
Other[2][3]	81.3	801.1	53.4	93.6	735.4	50.4	708.5	23.2	74.4	661.3
Total	$136.4	$ 2,566.5	$ 60.4	$ 95.0	$2,547.5	$107.4	$ 2,516.1	$ 29.2	$ 78.5	$2,515.8

(1) As of December 31, 2017, our equity in the underlying net assets of Stagecoach Gas exceeded our investment balance by approximately $51.4 million. This excess amount is entirely attributable to goodwill and, as such, is not subject to amortization. Our Stagecoach Gas investment is included in our storage and transportation segment.

(2) Includes our Jackalope, Tres Holdings, PRBIC and Crestwood Permian investments. As of December 31, 2017, our equity in the underlying net assets of Jackalope, Tres Holdings, PRBIC and Crestwood Permian exceeded our investment balance by approximately $0.7 million, $26.5 million, $6.4 million and $11.6 million, respectively. Our Tres Holdings and PRBIC investments are included in our storage and transportation segment and our Jackalope and Crestwood Permian investments are included in our gathering and processing segment.

(3) On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico. This contribution was treated as a transaction between entities under common control (because of our relationship with First Reserve) and the accounting standards related to such transactions requires Crestwood Permian to record the assets and liabilities of Crestwood New Mexico at our historical book value. The difference between our equity in Crestwood New Mexico's net assets and our investment balance is not subject to amortization.

Operating Results Data

	Year Ended December 31, 2017			2016			2015		
	Operating Revenues	Operating Expenses	Net Income	Operating Revenues	Operating Expenses	Net Income	Operating Revenues	Operating Expenses	Net Income
Stagecoach	$168.6	$ 77.7	$91.1	$99.3	$ 44.1	$ 55.3	$—	$ —	$ —
Other[1]	181.8	143.6	38.9	127.6	113.9	13.5	104.7	79.5	24.9
Total	$350.4	$ 221.3	$130.0	$226.9	$ 158.0	$ 68.8	$104.7	$ 79.5	$ 24.9

(1) Includes our Jackalope, Tres Holdings, PRBIC and Crestwood Permian equity investments. We amortize the excess basis in certain of our equity investments as an increase in our earnings from unconsolidated affiliates. We recorded amortization of the excess basis in our Jackalope equity investment of less than $0.1 million for both the

years ended December 31, 2017 and 2016, and $3.0 million for the year ended December 31, 2015, which we amortize over the life of Jackalope's gathering agreement with Chesapeake Energy Corporation (Chesapeake). We recorded amortization of the excess basis in our Tres Holdings equity investment of approximately $1.3 million for each of the years ended December 31, 2017, 2016 and 2015, which we amortize over the life of Tres Palacios' sublease agreement. We recorded amortization of the excess basis in our PRBIC equity investment of approximately $0.6 million and $1.6 million for the years ended December 31, 2017 and 2016, which we amortize over the life of PRBIC's property, plant and equipment and its agreement with Chesapeake.

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Distributions and Contributions

	Distributions Year Ended December 31,			Contributions Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
Stagecoach Gas	$47.3	$16.0	$—	$0.8	$—	$—
Jackalope(1)	26.3	27.4	12.5	3.5	1.4	25.4
Tres Holdings(2)	9.0	8.5	7.4	5.6	11.0	5.7
PRBIC(1)	1.6	2.0	1.9	—	—	10.7
Crestwood Permian(3)	23.4	—	—	117.5	—	—
Total	$107.6	$53.9	$21.8	$127.4	$12.4	$41.8

(1) Jackalope and PRBIC are required to make quarterly distributions of its available cash to its members based on their respective ownership percentage. We received a cash distribution of $7.4 million from Jackalope in January 2018, and we received a cash distribution of $0.3 million from PRBIC in February 2018.

(2) Tres Holdings is required, within 30 days following the end of each quarter, to make quarterly distributions of its available cash (as defined in its limited liability company agreement) to its members based on their respective ownership percentage.

(3) On June 21, 2017, we contributed to Crestwood Permian 100% of the equity interest of Crestwood New Mexico at our historical book value of approximately $69.4 million. This contribution was treated as a non-cash transaction between entities under common control.

Stagecoach Gas. Stagecoach Gas is required, within 30 days following the end of each quarter, to distribute 65% and 35% of its available cash (as defined in its limited liability company agreement) to CEGP and us, respectively. Because our ownership and distribution percentages differ, we determine the equity earnings from Stagecoach Gas using the Hypothetical Liquidation at Book Value (HLBV) method. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that we would receive if Stagecoach Gas were to liquidate all of its assets, as valued in accordance with GAAP, and distribute that cash to the members. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is our share of the earnings or losses from the equity investment for the period, which approximates how earnings are allocated under the terms of the limited liability company agreement. In January 2018, we received a cash distribution from Stagecoach Gas of approximately $11.3 million.

Crestwood Permian. Crestwood Permian is required, within 30 days following the end of each quarter to distribute 100% of its available cash (as defined in its limited liability company agreement) to its members based on their respective ownership percentages. Pursuant to Crestwood Permian's limited liability company agreement, we will receive 100% of Crestwood New Mexico's available cash (as defined in the limited liability company agreement) until the earlier of the Orla processing plant in-service date or June 30, 2018, at which time the distributions will be based on the members respective ownership percentages. Because our ownership and distribution percentages will differ during this period, equity earnings from Crestwood Permian is determined using the HLBV method. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that we would receive if Crestwood Permian were to liquidate all of its assets, as valued in accordance with GAAP, and distribute that cash to the members. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is our share of the earnings or losses from the equity investment for the period, which approximates how earnings are allocated under the terms of the limited liability company agreement. In January 2018, we received a cash distribution from Crestwood Permian of approximately $4.3 million.

Note 7 – Risk Management

We are exposed to certain market risks related to our ongoing business operations. These risks include exposure to changing commodity prices. We utilize derivative instruments to manage our exposure to fluctuations in commodity prices, which is discussed below. Additional information related to our derivatives is discussed in Note 2 and Note 8.

Commodity Derivative Instruments and Price Risk Management

Risk Management Activities

We sell NGLs and crude oil to energy related businesses and may use a variety of financial and other instruments including forward contracts involving physical delivery of NGLs, heating oil and crude oil. We periodically enter into offsetting positions

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to economically hedge against the exposure our customer contracts create. Certain of these contracts and positions are derivative instruments. We do not designate any of our commodity-based derivatives as hedging instruments for accounting purposes. Our commodity-based derivatives are reflected at fair value in the consolidated balance sheets, and changes in the fair value of these derivatives that impact the consolidated statements of operations are reflected in costs of product/services sold. During the years ended December 31, 2017, 2016 and 2015, the impact to our consolidated statements of operations related to our commodity-based derivatives reflected in costs of product/services sold was a loss of $31.2 million, a loss of $7.8 million and a gain of $18.9 million, respectively. We attempt to balance our contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. This balance in the contractual portfolio significantly reduces the volatility in costs of product/services sold related to these instruments.

Commodity Price and Credit Risk

Notional Amounts and Terms

The notional amounts and terms of our derivative financial instruments include the following:

	December 31, 2017		December 31, 2016	
	Fixed Price Payor	Fixed Price Receiver	Fixed Price Payor	Fixed Price Receiver
Propane, crude and heating oil (MMBbls)	15.3	17.5	13.1	15.1
Natural gas (MMcf)	780	660	—	—

Notional amounts reflect the volume of transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not reflect our monetary exposure to market or credit risks.

All contracts subject to price risk had a maturity of 34 months or less; however, 88% of the contracted volumes will be delivered or settled within 12 months.

Credit Risk

Inherent in our contractual portfolio are certain credit risks. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing credit risk and have established control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with our price risk management activities are energy marketers and propane retailers, resellers and dealers.

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2017 and 2016, was $28.9 million and $13.9 million. At December 31, 2017 and 2016, we posted less than $0.1 million of collateral for our commodity derivative instruments with credit-risk-related contingent features. In addition, at December 31, 2017 and 2016, we had a New York Mercantile Exchange (NYMEX) related net derivative asset position of $27.2 million and $14.3 million, for which we posted $5.6 million and $4.2 million of cash collateral in the normal course of business. At December 31, 2017 and 2016, we also received collateral of $3.7 million and $4.3 million in the normal course of business. All collateral amounts have been netted against the asset or liability with the respective counterparty and are reflected in our consolidated balance sheets as assets and liabilities from price risk management activities.

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Note 8 – Fair Value Measurements

The accounting standard for fair value measurement establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and US government treasury securities.

- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter (OTC) forwards, options and physical exchanges.

- Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Cash, Accounts Receivable and Accounts Payable

As of December 31, 2017 and 2016, the carrying amounts of cash, accounts receivable and accounts payable approximate fair value based on the short-term nature of these instruments.

Credit Facility

The fair value of the amounts outstanding under our CMLP credit facility approximates the carrying amounts as of December 31, 2017 and 2016, due primarily to the variable nature of the interest rate of the instrument, which is considered a Level 2 fair value measurement.

Senior Notes

We estimate the fair value of our senior notes primarily based on quoted market prices for the same or similar issuances (representing a Level 2 fair value measurement). The following table reflects the carrying value (reduced for deferred financing costs associated with the respective notes) and fair value of our senior notes (in millions):

	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
2020 Senior Notes	$—	$—	$340.6	$350.2
2022 Senior Notes	$—	$—	$429.3	$447.3
2023 Senior Notes	$692.1	$728.8	$690.6	$722.6
2025 Senior Notes	$492.3	$517.9	$—	$—

Financial Assets and Liabilities

As of December 31, 2017 and 2016, we held certain assets and liabilities that are required to be measured at fair value on a recurring basis, which include our derivative instruments related to heating oil, crude oil, and NGLs. Our derivative instruments consist of forwards, swaps, futures, physical exchanges and options.

Our derivative instruments that are traded on the NYMEX have been categorized as Level 1.

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Our derivative instruments also include OTC contracts, which are not traded on a public exchange. The fair values of these derivative instruments are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. These instruments have been categorized as Level 2.

Our OTC options are valued based on the Black Scholes option pricing model that considers time value and volatility of the underlying commodity. The inputs utilized in the model are based on publicly available information as well as broker quotes. These options have been categorized as Level 2.

Our financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth by level within the fair value hierarchy, our financial instruments that were accounted for at fair value on a recurring basis at December 31, 2017 and 2016 (in millions):

	December 31, 2017						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/Margin Received or Paid	Recorded in Balance Sheet
Assets							
Assets from price risk management	$1.1	$102.2	$ —	$103.3	$(74.6)	$(21.5)	$7.2
Suburban Propane Partners, L.P. units[2]	3.5	—	—	3.5	—	—	3.5
Total assets at fair value	$4.6	$102.2	$ —	$106.8	$(74.6)	$(21.5)	$10.7
Liabilities							
Liabilities from price risk management	$1.4	$118.2	$ —	$119.6	$(74.6)	$3.9	$48.9
Total liabilities at fair value	$1.4	$118.2	$ —	$119.6	$(74.6)	$3.9	$48.9

	December 31, 2016						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/Margin Received or Paid	Recorded in Balance Sheet
Assets							
Assets from price risk management	$0.6	$84.4	$ —	$85.0	$(67.8)	$(10.9)	$6.3
Suburban Propane Partners, L.P. units[2]	4.3	—	—	4.3	—	—	4.3
Total assets at fair value	$4.9	$84.4	$ —	$89.3	$(67.8)	$(10.9)	$10.6