Crestwood Equity Partners LP
Form 10-K
February 22, 2019
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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, 2018
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 29, 2018).

Crestwood Equity Partners LP	$1.6 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 11, 2019).

Crestwood Equity Partners LP	$30.89 per common unit	71,901,462
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.
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.
MMbtu	One million British thermal units, which is approximately equal to one Mcf. One British thermal unit is equivalent to an amount of heat required to raise the temperature of one pound of water by one degree.
MBbls	One thousand barrels.
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).
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.
	See gas storage capacity (above).

Working gas
storage
capacity

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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, 2018.

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. Our primary business objective is to maximize the value of Crestwood for our unitholders. 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. In addition, through our equity investments in joint ventures, we have ownership interests in their respective operating assets. Our operating assets, including those of our joint ventures, primarily include:

- natural gas facilities with approximately 2.9 Bcf/d of gathering capacity, 0.9 Bcf/d of processing capacity, 75.8 Bcf of certificated working storage capacity and 1.6 Bcf/d of firm transportation capacity;
- crude oil facilities with approximately 125,000 Bbls/d of gathering capacity, 1.9 MMBbls of storage capacity, 20,000 Bbls/d of transportation capacity and 180,000 Bbls/d of rail loading capacity;
- NGL facilities with approximately 2.5 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 1.3 MMBbls/d of NGLs; and
- produced water gathering facilities with approximately 90,000 Bbls/d of gathering capacity.

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Ownership Structure

The diagram below reflects a simplified version of our ownership structure as of December 31, 2018:

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, 2018.

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

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

Our Assets

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

The table below summarizes certain information about our G&P systems (including our equity investments) as of December 31, 2018:

Shale Play (State)	Counties / Parishes	Pipeline (Miles)	Gathering Capacity	2018 Average Gathering Volumes	Compression (HP)	Number of In-Service Processing Plants	Processing Capacity (MMcf/d)	Gross Acreage Dedication
Bakken North Dakota	McKenzie and Dunn	691 (1)	120 MMcf/d - natural gas gathering 125 MBbls/d - crude oil gathering 90 MBbls/d - water gathering	66 MMcf/d - natural gas gathering 78 MBbls/d - crude oil gathering 46 MBbls/d - water gathering	26,560	1	30	150,000
Marcellus West Virginia	Harrison and Doddridge	74	875 MMcf/d	377 MMcf/d	131,380	—	—	140,000
Barnett Texas	Hood, Somervell, Tarrant, Johnson and Denton	507	925 MMcf/d	278 MMcf/d	153,465	1	425	140,000
Fayetteville Arkansas	Conway, Faulkner, Van Buren, and White	173	510 MMcf/d	39 MMcf/d	18,670	—	—	143,000
Delaware Permian (2)	Eddy (New Mexico)	265	306 MMcf/d	156 MMcf/d	72,090 (3)	3	285	214,000

New Mexico/Texas	Loving, Reeves, Ward, Culberson (Texas)							
Powder River Basin [4] Wyoming	Converse	211	140 MMcf/d	103 MMcf/d	50,895	1	145	358,000

(1) Consists of 287 miles of natural gas gathering pipeline, 187 miles of crude oil gathering pipeline, and 217 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

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 the Fort Berthold Indian Reservation. Located approximately 60 miles southeast of the COLT Hub, the Arrow system

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connects to our COLT Hub through the Kinder Morgan Inc.'s (Kinder Morgan) Double H Pipeline system and Marathon Petroleum Corporation (Marathon) crude oil pipeline systems, as well as to Patoka, Illinois and Gulf Coast markets through the Dakota Access Pipeline (DAPL) interstate pipeline system. The Arrow system consists of approximately 691 miles of low-pressure gathering pipelines, 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. During 2018, we completed the construction of a natural gas processing facility (Bear Den) and associated pipelines, and began construction of the Bear Den Plant Phase 2 expansion that will increase processing capacity to 150 MMcf/d. The Phase 2 expansion is expected to be in service by the third quarter of 2019. Our operations are anchored by long-term gathering contracts 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 and Doddridge Counties, West Virginia. These systems consist of 74 miles of low pressure gathering lines and nine compression and dehydration stations with 131,380 horsepower. Through these systems, we provide midstream services 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.

In the East AOD, we provide gathering, dehydration and compression services on a fixed-fee basis. We gather and ultimately redeliver our customers' natural gas 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 predominantly utilizing our West Union and Victoria compressor stations, each with a maximum capacity of 120 MMcf/d. Our agreements provide for a minimum volume commitment of approximately 50% of the throughput capacity of each compressor station through 2021.

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, Texas 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. 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, Arkansas) consist of three gas gathering, compression, dehydration and treating facilities. Our Wilson Creek system (Van Buren County, Arkansas) consists of a gas gathering system and related dehydration and compression facilities. Our Rose Bud system (White County, Arkansas) 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

Our gathering and processing segment includes our 50% equity interest in the Crestwood Permian joint venture, which we account for under the equity method of accounting. Crestwood Infrastructure Holdings LLC (Crestwood Infrastructure), our wholly-owned subsidiary, and an affiliate of First Reserve formed the joint venture in October 2016. 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 85 MMcf/d of processing capacity that serves our customers in Eddy County, New Mexico. The joint venture owns a 200MMcf/d natural gas processing facility in Orla, Texas, (the Orla plant) and the Orla Express Pipeline, a 33 mile, 20-inch high pressure line connecting the existing Willow Lake system with the Orla plant. We manage the joint venture under a long-term management agreement. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Crestwood Permian.

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The Crestwood Permian joint venture owns a 50% equity interest in Crestwood Permian Basin LLC (Crestwood Permian Basin) and Shell Midstream Partners L.P. (Shell Midstream), a subsidiary of Royal Dutch Shell plc, owns the remaining 50% equity interest in Crestwood Permian Basin. Crestwood Permian Basin has a long-term agreement with SWEPI LP (SWEPI), a subsidiary of Royal Dutch Shell plc, to own and operate the Nautilus gathering system in SWEPI's operated position in the Delaware Permian. SWEPI has dedicated to Crestwood Permian Basin the gathering rights for SWEPI's gas production across a large acreage position in Loving, Reeves and Ward Counties, Texas. The Nautilus gathering system includes 59 receipt point meters, 133 miles of pipeline, a 41-mile high pressure header system, 37,400 horsepower of compression and four high pressure delivery points. Crestwood Permian Basin provides gathering, dehydration, compression and liquids handling services to SWEPI under a 20-year fixed-fee gathering agreement.

In July 2018, a subsidiary of Crestwood Permian purchased an undivided interest in 80,000 Bbls/d of capacity in a segment of the Epic Y-Grade Pipeline, LP (EPIC) pipeline from Orla, Texas to Benedum, Texas, where the pipeline interconnects with Chevron Phillips Chemical Company, LP's (Chevron Phillips) pipeline. Contemporaneous with this transaction, the subsidiary of Crestwood Permian also entered into a purchase and sale agreement with Chevron Phillips to sell a dedicated volume of barrels to be delivered off the EPIC pipeline to Chevron Phillips' pipeline. Our ownership in the EPIC pipeline provides a competitive NGL takeaway solution to continue growing our G&P footprint in the Delaware Basin. Additionally, going forward, we are positioned to securely and economically move Orla NGL products into Gulf Coast markets which provides our customers optionality and flow assurance that creates a unique competitive advantage for us.

Powder River Basin

Our gathering and processing 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 145 MMcf/d processing plant (Bucking Horse). The system connects to 102 well pads and is supported by a 20-year gathering and processing agreement with Chesapeake that includes minimum revenue guarantees for a five to seven year period. In addition, Jackalope is expanding its gathering system and Bucking Horse processing plant to increase processing capacity to 345 MMcf/d in late 2019/early 2020. The Phase 2 Jackalope expansion also includes gathering, compression and a second processing plant which will add an additional 200 MMcf/d to the Jackalope system. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment in Jackalope.

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The table below summarizes certain contract information of our G&P operations (including our equity investments) as of December 31, 2018:

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	9
	Processing	Mixed	—	WPX, Bruin E&P Partners, LLC, Rimrock Energy Partners, LLC, XTO Energy, QEP Resources, Inc., Enerplus	9
Marcellus	Gathering	Fixed-fee	140,000	Antero	13
	Compression	Fixed-fee	—	Antero	2
Barnett	Gathering	Mixed	140,000	BlueStone, Newark Acquisition I L.P. (Newark), Tokyo Gas America Ltd. (Tokyo Gas)	7
	Processing	Mixed	—	BlueStone, Newark, Tokyo Gas	7
Fayetteville	Gathering	Fixed-fee	143,000	Merit Energy Company (Merit)	6
	Treating	Fixed-fee	—	Merit	6
Delaware Permian	Gathering	Fixed-fee	214,000	Mewbourne, Marathon, Concho Resources (Concho), SWEPI, Halcon Resources Corporation	15
	Processing	Mixed	—	Mewbourne, Marathon, Concho	3
Powder River Basin	Gathering	Fixed-fee	358,000	Chesapeake	20
	Processing	Fixed-fee	—	Chesapeake	20

(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.

We provide gathering, processing, compression, storage and transportation services under a variety of contracts. 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. The cash flows from our G&P operations can also be impacted in the short term by changing commodity prices, seasonality and weather fluctuations. 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 segment includes 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 1.6 Bcf/d, and crude oil facilities with approximately 380,000 Bbls of working storage capacity and 20,000 Bbls/d of rail loading capacity.

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 pipelines and the DAPL interstate pipeline system at the COLT terminal, and the Enbridge Energy Partners, L.P. and Marathon interstate pipeline systems at Dry Fork. The pipelines connected to the COLT Hub can deliver up to approximately 290,000 Bbls/d of crude oil to our terminal.

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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. 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 storage and transportation business located in the Northeast (the NE S&T assets). We manage the joint venture's operations under a long-term management agreement. 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, include:

- Stagecoach - a FERC certificated 26.2 Bcf multi-cycle, depleted reservoir storage facility. 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. 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. 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. 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 Markham, Texas. We manage the joint venture's operations under a long-term management agreement.

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's Houston central processing plant. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of our investment interest in Tres Palacios.

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The following provides additional information about the natural gas storage facilities of our S&T equity investments as of December 31, 2018:

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	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[2]
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) 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 603 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 974 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.

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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 New York State Public Service Commission.

Rail Loading Facility. Our storage and transportation segment includes our 50.01% equity interest in Powder River Basin Industrial Complex, LLC (PRBIC), which we account for under the equity method of accounting. PRBIC owns an integrated crude oil loading, storage and pipeline terminal located in Douglas County, Wyoming. PRBIC, which is operated by our joint venture partner, Twin Eagle Resource Management, LLC, 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 pipeline terminal includes connections to Kinder Morgan's Double H Pipeline system and Plains All American Pipeline's Rocky Mountain Pipeline system. 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, 2018:

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	37 MBbl/d	BP p.l.c., Flint Hills Resources, Sunoco Logistics	1
NE S&T Joint Venture:					
North-South Facilities	Transportation	Firm	603 MMcf/d	Southwestern Energy, Consolidated Edison	2
MARC I Pipeline	Transportation	Firm	974 MMcf/d	Chesapeake, Chief Oil and Gas, Alta Energy Marketing	3
East Pipeline	Transportation	Firm	30 MMcf/d	NY State Electric & Gas Corp	2
Stagecoach	Storage	Firm	20.4 Bcf	Consolidated Edison, New Jersey Natural Gas, Sequent Energy Management (Sequent)	2
Thomas Corners	Storage	Firm	6.7 Bcf	Tenaska Gas Storage, LLC, Engie Energy Marketing (Engie), Green Plains Trade Group	1
Seneca Lake	Storage	Firm	1.5 Bcf	NY State Electric & Gas Corp, DTE Energy Trading, Texla Energy Management	2
Steuben	Storage	Firm	5.2 Bcf	Pivotal Utility Holdings, Sequent, Tenaska Gas Storage LLC	2
Tres Palacios Joint Venture	Storage	Firm	29.3 Bcf	Brookfield Infrastructure Group, Engie, J Aron and Company, Sequent, Trafigura Trading LLC	1
PRBIC Joint Venture	Rail Loading	Fixed-fee	—	Chesapeake	Month-to-month

(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.

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 NGL and crude marketing and logistics operations. We utilize our trucking 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.

Our NGL marketing and logistics operations primarily include:

- A fleet of rail and rolling stock with 1,155,000 Bbls/d of NGL transportation capacity, which also includes our rail-to-truck terminals located in Florida, New Jersey, New York, Rhode Island, North Carolina and Pennsylvania.
- A fleet of owned and leased trucks with 20,000 Bbls/d of crude oil transportation capacity and 100,000 Bbls/d of NGL transportation capacity. We provide hauling services to customers in over 30 states from New Mexico to Maine.
- 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.
- 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.

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.

Customers

For the years ended December 31, 2018, 2017 and 2016, 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 a cost-effective and safe 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.

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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.

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.

Our NGL marketing 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.

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.

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).

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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. This final rule has not been issued under the current administration. The interim rule remains in effect. 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 proposed or enacted, legislation or regulations imposing more stringent or costly requirements for exploration and production companies to develop and produce hydrocarbons.

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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.

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 wherein the agency adopted legally enforceable "gas capture percentage goals" requiring our customers to capture certain percentages of natural gas produced by specified dates (Gas Capture Order). The Gas Capture Order was subsequently modified in late 2015 and late 2018. 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. 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.

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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 has not yet issued. 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 have evaluated the final interim rules and do not anticipate any significant impact on our equity investments or any significant increase in 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 natural 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.

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.

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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.

Marketing, 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 the operations of our equity 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 the operations of our equity 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;
- 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
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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 this matter.

Employees

As of February 11, 2019, we had 859 full-time employees, 336 of which were general and administrative employees and 523 of which were operational employees. We believe that our relationship with our employees is satisfactory.

Available Information

Our website is located at www.crestwoodlp.com. We make available, free of charge, on or through our website our annual reports on Form 10-K, which include our audited financial statements, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the

Exchange Act as soon as we electronically file such material with the SEC. These documents are also available, free of charge, at the SEC's website at www.sec.gov. In addition, copies of these documents, excluding exhibits, may be requested at no cost by contacting Investor Relations, Crestwood Equity Partners LP 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.

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Item 1A. Risk Factors

Risks Inherent in Our Business

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

Our success depends on the supply and demand for natural gas, NGLs and crude oil, 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 throughout 2017 and 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 production cuts and freezes implemented by Organization of the Petroleum Exporting Countries (OPEC) members and other large oil producers such as 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:

- changes in general domestic and global economic and political conditions;
- 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;
- impact of interest rates on economic activity;
- 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 increase, 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 $44.48 to $76.40 per barrel in 2018, the sustainability of recent price 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 volatility 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 historic increased trading volatility. 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 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

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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.

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.

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.

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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 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.

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.

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Under GAAP, during the years ended December 31, 2017 and 2016, we were required to record $121.0 million and $194.0 million of long-lived asset and goodwill impairments related to certain of our reporting units because changes in circumstances or events 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. 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 $1.8 billion of long-term debt outstanding as of December 31, 2018. If we are unable to generate sufficient cash flow to satisfy debt obligations or to obtain alternative financing, that 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;
- 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;
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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.

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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 our 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 our 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.”

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 partners or participants in certain areas of mutual interest.

In addition, joint venture partners 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, 2018, the weighted average remaining term of our consolidated portfolio of natural gas gathering contracts is approximately nine years, and our consolidated portfolio of crude oil gathering contracts is approximately eight 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 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.

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On March 15, 2018, the FERC issued a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost-of-service rates. Also on March 15, 2018, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to pipeline rates. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from providing support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors’ income tax costs. Also on July 18, 2018, the FERC issued a final rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the final rule requires all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to select one of four options: (i) file a limited NGA Section 4 filing reducing its rates only as required related to the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement; (ii) commit to filing a general NGA Section 4 rate case in the near future; (iii) file a statement explaining why an adjustment to rates is not needed; or (iv) take no other action. Stagecoach Gas submitted its Form No. 501-G on December 6, 2018.

The FERC also issued a Notice of Inquiry (NOI) requesting comments about whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Any actions the FERC will take related to the NOI are unknown at this time, but could impact the rates midstream companies are permitted to charge its customers for transportation services in the future. At this time, we cannot predict the outcome of the implementation of the Revised Policy Statement, the final rule or NOI, but the rates that our equity investments with FERC-regulated operations are permitted to charge its customers for transportation services after the expiration of the existing negotiated rates could be impacted if they file a limited or general NGA Section 4 rate filing or if the FERC or customers challenge the cost-of-service rates our equity investments are authorized to charge.

The FERC issued a NOI on April 19, 2018 (Certificate Policy Statement NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. Comments on the Certificate Policy Statement NOI were due on July 25, 2018, and we are unable to predict what, if any, changes may be proposed as a result of the NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective.

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

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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, tribal, 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, imposition of restoration and remedial liabilities with respect to abandonment of facilities and for any contamination resulting from our operations, 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 or cancellations 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 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 2015, the EPA issued a final rule under the federal Clean Air Act lowering the United States National Ambient Air Quality Standards (NAAQS) for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone either “attainment/unclassifiable” or “unclassifiable” or “non-attainment.” Additionally, in November 2018, the EPA issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. In another example, the EPA and U.S. Army of Corps of Engineers (Corps) published a final rule in 2015 that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, but legal challenges to this rule have followed and, as a result, the rule is currently in effect in only twenty-two states, pending resolution of the various court challenges. In July 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rule and, in February 2018, the agencies published a final rule adding a February 6, 2020 applicable date to the 2015 rule. The February 2018 rule extending the 2015 final rule’s date of applicability is currently subject to litigation. As a result of these developments, future implementation of the 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 or cancellations 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, restrictions or cancellations 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, political 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. In November 2018, the Trump Administration released the second volume of the fourth inter-agency National Climate Assessment that is issued pursuant to federal law, which current version outlines potentially severe climate-related impairments for the United States' environment, economy and public health, now and in the future, that is indicated to worsen over time unless significant measures are taken to, among other things, reduce GHG emissions. This report could serve as a basis for increasing governmental pursuit of policies to restrict GHG emissions.

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At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that GHG emissions present a danger to public health and the environment and 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 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. In June 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years but the rule has not been finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule and, in September 2018, the agency proposed amendments that include rescission or revision of specific rule requirements, such as fugitive emission monitoring frequency. In another example, the BLM published a final rule in late 2016 that imposes requirements to reduce methane emissions by regulating venting, flaring, and leaking from oil and natural gas operations on public lands; however, in September 2018, the BLM published a final rule rescinding most of the new requirements of the 2016 final rule and codifies the BLM’s prior approach to venting and flaring, which rescission has been challenged in federal court and remains pending. 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, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France (Paris Agreement) for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020. 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, which provides for a four year exit process beginning when it took effect in November 2016.

The adoption of legislation or regulatory programs to reduce emissions of GHGs in areas where we or our customers conduct operations 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,” which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological 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.

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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, federal legislation or implementing regulations adopted in recent years 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 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. 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 natural gas storage facilities, following the detection of a natural gas leak from a third party at a natural gas storage facility in California in 2015, PHMSA issued an advisory bulletin in 2016 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. Additionally, the 2016 Pipeline Safety Act required PHMSA to develop new safety standards for such storage facilities by June 2018. In response, PHMSA issued final interim rules in December 2016 that imposed 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 adopted and made mandatory two American Petroleum Institute Recommended Practices (API RP 1170 and 1171) that, among other things, address construction, maintenance, risk-management and integrity-management procedures. However, in June 2017, PHMSA temporarily suspended specified enforcement actions pertaining to provisions that had previously been non-mandatory provisions under those API recommended practices prior to incorporation into the December 2016 interim final rule, as PHMSA announced it would reconsider the interim final rule, and subsequently re-opened the rule to public comment in October 2017. The Unified Agenda issued by the federal government published a September 2018 date for issuance of a final rule but no rule has yet been finalized. 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 has been delayed 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. Additionally, while states are largely preempted by federal law from regulating pipeline safety for interstate pipelines, most states are certified by the U.S. 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. 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. With regard to easements and rights-of-way on tribal lands, following a court decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, 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 Indian landowner) bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted tribal lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way without experiencing significant costs.

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 results of operations 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 for 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 or utilize our customer service systems. Also, destructive forms of protests and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas development and production or midstream processing or transportation activities could potentially result in damage or injury to persons, property or the environment or lead to extended interruptions of our or our customers' operations. Additionally, the oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain processing and operational activities. At the same time, companies in our industry have been the targets of cyber-attacks, and it is possible that the attacks in our industry will continue and grow in number. In addition, to assist in conducting our business, we rely on information technology systems and data hosting facilities, including systems and facilities that are hosted by third parties and with respect to which we have limited visibility and control. These systems and facilities may be vulnerable to a variety of evolving cyber security risks or information security breaches, including unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions. These cyber security risks could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary, personal data, and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as advanced persistent threats, may remain undetected for an extended period. The occurrence of any of these events, including any attack or threat targeted at our pipelines and other assets, could cause a substantial decrease in revenues, increased costs or other financial losses, exposure or loss of customer information, damage to our reputation or business relationships, increased regulation or litigation, disruption of our operations 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. Although we have adopted controls and systems, including procuring limited insurance for certain cyber-related losses, that are designed to protect information and mitigate the risk of data loss and other cyber security events, such measures cannot entirely eliminate cyber security threats, particularly as these threats continue to evolve and grow. Furthermore the controls and systems we have installed may be breached or be inadequate to address a risk that arises. We are not aware of any cyber security events that impacted our company that have or could have resulted in a material loss; however there is no assurance that we will not suffer such a loss in the future.

We are or may become subject to cyber security and data privacy laws, regulations, litigation and directives relating to our processing of personal data.

Several jurisdictions in which we operate throughout the United States may have laws governing how we must respond to a cyber incident that results in the unauthorized access, disclosure, or loss of personal data. Additionally, new laws and regulations governing data privacy and unauthorized disclosure of confidential information, including international comprehensive data privacy regulations and recent California legislation (which, among other things, provides for a private right of action), pose increasingly complex compliance challenges and could potentially elevate our costs over time. Our business involves collection, uses, and other processing of personal data of our employees, contractors, suppliers, and service providers. As legislation continues to develop and cyber incidents continue to evolve, we will likely be required to expend significant resources to continue to modify or enhance our protective measures to comply with such legislation and to detect, investigate and remediate vulnerabilities to cyber incidents. Any failure by us, or a company we acquire, to comply with such laws and regulations could result in reputational harm, loss of goodwill, penalties, liabilities, and/or mandated changes in our business practices.

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 paid.

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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 operations and maintenance and general and 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.

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 significant 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 unitholders.

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.

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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 vote on any matter.

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.

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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, 2018, 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 unitholders. 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 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 unitholders 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 risk factor "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.

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- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- Our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

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

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

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

If at any time our general partner and its affiliates own more than 80% of our outstanding units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2018, the directors and executive officers of our general partner owned approximately 7% 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 and current Treasury Regulations, 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,

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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 have proposed and considered substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including a prior legislative proposal that 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, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impair our ability to qualify as a publicly traded partnership in the future.

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 changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. You are urgedto consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your 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 adjustments 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 adjustments 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 and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustments into account and pay any resulting taxes (including applicable penalties or interest) 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.

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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 from the sale of our units, 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 owning our 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, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) 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 common 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 Cuts 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 interests 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 actually 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 have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods 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 any 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 generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The 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 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 to have 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 securities loan are urged to consult a tax advisor to determine whether it is advisable to 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 income tax 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 may 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 conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders' responsibility to file all required U. S. federal, state, local and foreign tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

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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 own or lease the property rights necessary to conduct our operations and we also lease and rely upon our customers' property rights to conduct a substantial part of our 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.

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.

The last reported sale price of Crestwood Equity’s common units on the NYSE on February 11, 2019, was $30.89. As of that date, Crestwood Equity had 71,901,462 common units issued and outstanding, which were held by 265 unitholders of record.

Issuer Purchases of Equity Securities

For the year ended December 31, 2018, we relinquished 221,576 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 CEQP’s equity compensation plan information as of December 31, 2018:

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	—	$ —	4,963,263
Total	—	$ —	4,963,263

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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. The income statement and cash flow data for each of the three years ended December 31, 2018 and balance sheet data as of December 31, 2018 and 2017 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, 2015 and the balance sheet data as of December 31, 2016, 2015 and 2014 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, 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, the change in fair value of commodity inventory-related derivative contracts, costs associated with the realignment of our operations (including the Simplification Merger, Marketing, Supply and Logistics operational realignment and other cost savings initiatives), 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,				
	2018	2017	2016	2015	2014
	(in million, except per unit data)				
Statement of Income Data:					
Revenues	$3,654.1	$3,880.9	$2,520.5	$2,632.8	$3,931.3
Operating income (loss)	113.5	(79.4)	(108.7)	(2,084.8)	117.9
Income (loss) before income taxes	67.1	(167.4)	(191.8)	(2,305.1)	(9.3)
Net income (loss)	67.0	(166.6)	(192.1)	(2,303.7)	(10.4)
Net income (loss) attributable to Crestwood Equity Partners LP	50.8	(191.9)	(216.3)	(1,666.9)	56.4
Performance Measures:					
Diluted net income (loss) per limited partner unit: (1)	$(0.13)	$(3.64)	$(3.55)	$(54.00)	$3.30
Distributions declared per limited partner unit(2)	$2.40	$2.40	$3.175	$5.50	$5.50
Other Financial Data:					
EBITDA (unaudited)	$335.9	$161.4	$152.9	$(1,844.9)	$403.1
Adjusted EBITDA (unaudited)	420.1	395.4	455.6	527.4	495.9
Net cash provided by operating activities	253.6	255.9	346.1	440.7	283.0
Net cash provided by (used in) investing activities	(241.2)	38.7	867.2	(212.7)	(483.0)
Net cash provided by (used in) financing activities	3.5	(294.9)	(1,212.2)	(236.3)	203.6
Balance Sheet Data:					
Property, plant and equipment, net	$2,029.7	$1,820.8	$2,097.6	$3,310.8	$3,893.8
Total assets	4,294.5	4,284.9	4,448.9	5,762.8	8,421.7
Total debt, including current portion	1,753.3	1,492.2	1,523.7	2,502.9	2,356.8
Other long-term liabilities(3)	173.6	104.7	44.6	47.5	47.2
Partners' capital	2,033.8	2,180.5	2,539.0	2,946.9	5,584.5

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	Crestwood Equity Partners LP Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions)				
Reconciliation of Net Income (Loss) to EBITDA and Adjusted EBITDA:					
Net income (loss)	$67.0	$(166.6)	$(192.1)	$(2,303.7)	$(10.4)
Interest and debt expense, net	99.2	99.4	125.1	140.1	127.1
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)	20.0	—
Provision (benefit) for income taxes	0.1	(0.8)	0.3	(1.4)	1.1
Depreciation, amortization and accretion	168.7	191.7	229.6	300.1	285.3
EBITDA	335.9	161.4	152.9	(1,844.9)	403.1
Unit-based compensation charges	28.5	25.5	19.2	19.7	21.3
Loss on long-lived assets, net(4)	28.6	65.6	65.6	821.2	1.9
Goodwill impairment(5)	—	38.8	162.6	1,406.3	48.8
Loss on contingent consideration(6)	—	57.0	—	—	8.6
(Earnings) loss from unconsolidated affiliates, net(7)	(53.3)	(47.8)	(31.5)	60.8	0.7
Adjusted EBITDA from unconsolidated affiliates, net	95.6	80.3	61.1	25.3	6.9
Change in fair value of commodity inventory-related derivative contracts	(18.3)	2.2	14.1	5.4	(10.3)
Significant transaction and environmental-related costs and other items(8)	3.1	12.4	11.6	33.6	14.9
Adjusted EBITDA	$420.1	$395.4	$455.6	$527.4	$495.9

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	Crestwood Equity Partners LP				
	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions)				
Reconciliation of Net Cash Provided by Operating Activities to EBITDA and Adjusted EBITDA:					
Net cash provided by operating activities	$253.6	$255.9	$346.1	$440.7	$283.0
Net changes in operating assets and liabilities	46.9	(0.3)	(57.9)	(98.0)	73.8
Amortization of deferred financing costs and premiums	(6.8)	(7.2)	(6.9)	(8.9)	(8.5)
Interest and debt expense, net	99.2	99.4	125.1	140.1	127.1
Market adjustment on interest rate swaps	—	—	—	0.5	2.7
Unit-based compensation charges	(28.5)	(25.5)	(19.2)	(19.7)	(21.3)
Loss on long-lived assets, net(4)	(28.6)	(65.6)	(65.6)	(821.2)	(1.9)
Goodwill impairment(5)	—	(38.8)	(162.6)	(1,406.3)	(48.8)
Loss on contingent consideration(6)	—	(57.0)	—	—	(8.6)
Earnings (loss) from unconsolidated affiliates, net, adjusted for cash distributions received	(0.5)	0.1	(7.6)	(73.6)	(0.7)
Deferred income taxes	0.7	2.1	3.1	3.6	5.2
Provision (benefit) for income taxes	0.1	(0.8)	0.3	(1.4)	1.1
Other non-cash expense	(0.2)	(0.9)	(1.9)	(0.7)	—
EBITDA	335.9	161.4	152.9	(1,844.9)	403.1
Unit-based compensation charges	28.5	25.5	19.2	19.7	21.3
Loss on long-lived assets, net(4)	28.6	65.6	65.6	821.2	1.9
Goodwill impairment(5)	—	38.8	162.6	1,406.3	48.8
Loss on contingent consideration(6)	—	57.0	—	—	8.6
(Earnings) loss from unconsolidated affiliates, net(7)	(53.3)	(47.8)	(31.5)	60.8	0.7
Adjusted EBITDA from unconsolidated affiliates, net	95.6	80.3	61.1	25.3	6.9
Change in fair value of commodity inventory-related derivative contracts	(18.3)	2.2	14.1	5.4	(10.3)
Significant transaction and environmental-related costs and other items(8)	3.1	12.4	11.6	33.6	14.9
Adjusted EBITDA	$420.1	$395.4	$455.6	$527.4	$495.9

(1) 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 year ended December 31, 2014 were restated to reflect the 1-for-10 reverse split.

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

(3) 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.

(4) During 2018 and 2017, we recognized a loss of approximately $26.9 million from the sale of our West Coast facilities and a gain of approximately $33.6 million from the sale of US Salt, respectively. For a further discussion of these transactions, 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, Note 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.

(5) 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.

(6) 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, 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.

(7) During 2015, we recorded impairments of our PRBIC and Jackalope equity investments of approximately $23.4 million and $51.4 million.

(8) Significant transaction and environmental-related costs and other items primarily include costs incurred related to merger, acquisition and joint venture transactions, as well as costs associated with the realignment of our operations (including the Simplification Merger, Marketing Supply and Logistics operational realignment, and other cost savings initiatives).

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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. Our operating assets, including those of our joint ventures, primarily include:

- natural gas facilities with approximately 2.9 Bcf/d of gathering capacity, 0.9 Bcf/d of processing capacity, 75.8 Bcf of certificated working storage capacity and 1.6 Bcf/d of firm transportation capacity;
- crude oil facilities with approximately 125,000 Bbls/d of gathering capacity, 1.9 MMBbls of storage capacity, 20,000 Bbls/d of transportation capacity and 180,000 Bbls/d of rail loading capacity;
- NGL facilities with approximately 2.5 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 1.3 MMBbls/d of NGLs; and
- produced water gathering facilities with approximately 90,000 Bbls/d of gathering 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 marketing and logistics business, crude oil storage and rail loading facilities and fleet. For a description of the assets included in our operating and reporting segments, see Part I, Item 1. Business.

Gathering and Processing

Our G&P operations and investments provide gathering, compression, treating, and processing services to producers in multiple unconventional resource plays in North Dakota, West Virginia, Texas, New Mexico, Wyoming and Arkansas, 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.

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.

Marketing, Supply and Logistics

Our MS&L segment consists of our NGL marketing and logistics operations located in over 30 states, including Florida, Indiana, New Jersey, New York, North Carolina, Pennsylvania and Rhode Island. We utilize our trucking 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.

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.

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)

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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, Powder River Basin 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 to provide midstream services for crude oil, natural gas, and produced water, including gathering, storage and terminalling, condensate stabilization, truck loading/unloading options and connections to third party pipelines and produced water gathering, disposal and recycling in the Bakken Shale, Powder River Basin and Delaware Permian in the near term, while closely monitoring longer-term expansion opportunities in the 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 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, Powder River Basin, Delaware Permian and northeast Marcellus drive significant growth to the Company.

Segment Highlights

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. In addition, we are constructing a 120 MMcf/d cryogenic plant that we anticipate will be placed in-service in the third quarter of 2019 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. Upon completion of the expansion, we expect to have 150 MMcf/d of gas processing capacity in the Bakken. We believe the expansion of our gas processing capacity 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.

Powder River Basin. In the Powder River Basin, our Jackalope joint venture with Williams continues to benefit from increased drilling activity and better than anticipated well results. Jackalope is expanding its gathering system and Bucking Horse processing plant to increase processing capacity to 345 MMcf/d in late 2019/early 2020. The Phase 2 Jackalope expansion also includes gathering, compression and a second processing plant which will add an additional 200 MMcf/d to the Jackalope system.

Delaware Permian. In the Delaware Permian, we have identified gathering and processing and transportation opportunities in and around our existing assets, including our Crestwood Permian joint venture. Crestwood Permian Basin owns and operates the Nautilus system in SWEPI's operated position in the Delaware Permian. Crestwood Permian Basin provides gathering, dehydration, compression and liquids handling services to SWEPI under a 20-year fixed-fee gathering agreement. SWEPI has dedicated to Crestwood Permian Basin the 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 was further expanded and integrated in July 2018 to connect the Nautilus gas gathering system to the Orla plant.

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Marketing, Supply and Logistics

In October 2018, we sold our West Coast facilities to a third party for net proceeds of approximately $70.5 million. The West Coast assets included a gas gathering and processing system, fractionator, butamer and various rail and truck terminal and storage facilities located in California, Nevada, Wyoming and Utah.

During 2017 and 2018, we realigned our Marketing, Supply and Logistics operations, including leadership changes, cost reductions, resizing of our truck and rail fleet, and the implementation of rate and profitability key performance indicators. We believe these changes will result in improved profitability and operating efficiencies for this business in the future.

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. 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.
Effective December 2017, the Tax Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, the FERC issued a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost-of-service rates. Also on March 15, 2018, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to pipeline rates. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from providing support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. Also on July 18, 2018, the FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to select one of four options: (i) file a limited NGA Section 4 filing reducing its rates only as required related to the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement; (ii) commit to filing a general NGA Section 4 rate case in the near future; (iii) file a statement explaining why an adjustment to rates is not needed; or (iv) take no other action.

On March 15, 2018, the FERC also issued a Notice of Inquiry (NOI) requesting comments about whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Comments on the NOI were filed by May 21, 2018, and any actions the FERC may take following receipt of these responses to the NOI are unknown at this time, but could impact the rates midstream companies are permitted to charge its customers for transportation services in the future.

In addition, the FERC issued a NOI on April 19, 2018 (Certificate Policy Statement NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. Comments on the Certificate Policy Statement NOI were due on July 25, 2018, and we are unable to predict what, if any, changes may be proposed as a result of the NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

Although we do not have any consolidated operations that have FERC-regulated pipelines, two of our equity investments (Stagecoach Gas and Tres Holdings) have FERC-regulated operations. These equity investments receive revenues from contracts that primarily have market-based rates or negotiated rates that are not tied to cost-of-service rates, and we currently do not expect rates subject to negotiated rates or market-based rates to be affected by the Revised Policy Statement, the Final Rule or any final regulations that may result from the NOI. As a result, we currently do not believe that the Revised Policy Statement, the Final Rule or NOI will have a material impact on our results of operations, but we continue to monitor

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developments at the FERC related to these matters to assess whether the final regulations could have an impact on the future results of our equity investments.

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

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.

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 and 2016.

On January 1, 2018, we combined the four reporting units included in our MS&L segment into one NGL Marketing and Logistics reporting unit for the purpose of evaluating goodwill for impairment on an ongoing basis as shown in the table below. At January 1, 2018, the goodwill for these reporting units was approximately $101.7 million. We combined these reporting units based on a strategic shift in the way in which we manage, operate and report our NGL operations as an integrated platform instead of as four individual stand-alone operations. We attributed approximately $9.0 million of the goodwill associated with our NGL Marketing and Logistics reporting unit to the West Coast facilities during 2018, and this goodwill was written off in conjunction with the sale of the West Coast assets. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3 for a further discussion of the sale of our West Coast assets. We did not record any other impairments of our goodwill during 2018.

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The following table summarizes the goodwill impairments of our reporting units during 2017 and 2016 (in millions):

	Goodwill Impairments during the Year Ended December 31, 2016	Goodwill Impairments during the Year Ended December 31, 2017	Goodwill at December 31, 2018
G&P			
Marcellus	$ 8.6	$ —	$ —
Arrow	—	—	45.9
S&T			
COLT	44.9	—	—
MS&L			
NGL Marketing and Logisitics	—	—	92.7
West Coast	—	2.4	—
Supply and Logistics	65.5	—	—
Storage and Terminals	14.1	36.4	—
Trucking	29.5	—	—
Total	$ 162.6	$ 38.8	$ 138.6

We have two reporting units with goodwill associated with them at December 31, 2018 (Arrow and NGL Marketing 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. A 5% decrease in the forecasted cash flows or a 1% increase in the discount rates utilized to determine the fair value of our businesses would not have resulted in a goodwill impairment of either of our reporting units.

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 in 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

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that reporting unit. During 2018, we did not record impairments of our intangible assets and property, plant and equipment. During 2017 and 2016, 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. During 2018, we sold our MS&L West Coast operations for net proceeds of approximately $70.5 million, and recorded a $26.9 million of loss on long-lived assets associated with the sale. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3 for a further discussion of the sale of these assets.

- 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.

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 the 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.

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.

Our equity method investments have long-lived assets, intangible assets, goodwill and equity method investments in their underlying financial statements, and our equity investees apply similar accounting policies and have similar critical accounting estimates in assessing those assets for impairment as we do. During 2016, our PRBIC equity method investment recorded an impairment of its goodwill and intangible assets, and we reflected a $5.8 million reduction of our equity earnings from PRBIC related to our share of that impairment. Our Stagecoach Gas equity method investment has approximately $656.5 million of goodwill in its financial statements, which it assesses for impairment annually on December 31 or whenever events indicate that it is more likely than not that its fair value could be less than its carrying amount. This assessment requires Stagecoach Gas to make certain assumptions about its further operating performance (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, in addition to current and changing economic conditions and the commodity price environment). A significant decrease in the assumptions utilized by Stagecoach Gas could result in a significant reduction in our equity earnings from Stagecoach Gas. Our investment in Stagecoach Gas was approximately $830.4 million at December 31, 2018.

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 of 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, the change in fair value of commodity inventory-related derivative contracts, costs associated with the realignment of our operations (including our Marketing, Supply and Logistics operations and other cost savings initiatives), 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,	
	2018	2017	2016	2018	2017
Revenues	$3,654.1	$3,880.9	$2,520.5	$3,654.1	$3,880.9
Costs of product/services sold	3,129.4	3,374.7	1,925.1	3,129.4	3,374.7
Operations and maintenance	125.8	136.0	158.1	125.8	136.0
General and administrative	88.1	96.5	88.2	83.5	93.1
Depreciation, amortization and accretion	168.7	191.7	229.6	181.4	202.7
Loss on long-lived assets, net	(28.6)	(65.6)	(65.6)	(28.6)	(65.6)
Goodwill impairment	—	(38.8)	(162.6)	—	(38.8)
Loss on contingent consideration	—	(57.0)	—	—	(57.0)
Operating income (loss)	113.5	(79.4)	(108.7)	105.4	(87.0)
Earnings from unconsolidated affiliates, net	53.3	47.8	31.5	53.3	47.8
Interest and debt expense, net	(99.2)	(99.4)	(125.1)	(99.2)	(99.4)
Gain (loss) on modification/extinguishment of debt	(0.9)	(37.7)	10.0	(0.9)	(37.7)
Other income, net	0.4	1.3	0.5	—	0.8
(Provision) benefit for income taxes	(0.1)	0.8	(0.3)	—	—
Net income (loss)	67.0	(166.6)	(192.1)	58.6	(175.5)
Add:					
Interest and debt expense, net	99.2	99.4	125.1	99.2	99.4
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)	0.9	37.7
Provision (benefit) for income taxes	0.1	(0.8)	0.3	—	—
Depreciation, amortization and accretion	168.7	191.7	229.6	181.4	202.7
EBITDA	335.9	161.4	152.9	340.1	164.3
Unit-based compensation charges	28.5	25.5	19.2	28.5	25.5
Loss on long-lived assets, net	28.6	65.6	65.6	28.6	65.6
Goodwill impairment	—	38.8	162.6	—	38.8
Loss on contingent consideration	—	57.0	—	—	57.0
Earnings from unconsolidated affiliates, net	(53.3)	(47.8)	(31.5)	(53.3)	(47.8)
Adjusted EBITDA from unconsolidated affiliates, net	95.6	80.3	61.1	95.6	80.3
Change in fair value of commodity inventory-related derivative contracts	(18.3)	2.2	14.1	(18.3)	2.2
Significant transaction and environmental-related costs and other items	3.1	12.4	11.6	3.1	12.4
Adjusted EBITDA	$420.1	$395.4	$455.6	$424.3	$398.3

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	Crestwood Equity			Crestwood Midstream	
	Year Ended December 31,			Year Ended December 31,	
	2018	2017	2016	2018	2017
EBITDA:					
Net cash provided by operating activities	$253.6	$255.9	$346.1	$260.5	$262.2
Net changes in operating assets and liabilities	46.9	(0.3)	(57.9)	44.9	(2.4)
Amortization of deferred financing costs	(6.8)	(7.2)	(6.9)	(6.8)	(7.2)
Interest and debt expense, net	99.2	99.4	125.1	99.2	99.4
Unit-based compensation charges	(28.5)	(25.5)	(19.2)	(28.5)	(25.5)
Loss on long-lived assets, net	(28.6)	(65.6)	(65.6)	(28.6)	(65.6)
Goodwill impairment	—	(38.8)	(162.6)	—	(38.8)
Loss on contingent consideration	—	(57.0)	—	—	(57.0)
Earnings from unconsolidated affiliates, net, adjusted for cash distributions received	(0.5)	0.1	(7.6)	(0.5)	0.1
Deferred income taxes	0.7	2.1	3.1	0.1	—
Provision (benefit) for income taxes	0.1	(0.8)	0.3	—	—
Other non-cash expense	(0.2)	(0.9)	(1.9)	(0.2)	(0.9)
EBITDA	335.9	161.4	152.9	340.1	164.3
Unit-based compensation charges	28.5	25.5	19.2	28.5	25.5
Loss on long-lived assets, net	28.6	65.6	65.6	28.6	65.6
Goodwill impairment	—	38.8	162.6	—	38.8
Loss on contingent consideration	—	57.0	—	—	57.0
Earnings from unconsolidated affiliates, net	(53.3)	(47.8)	(31.5)	(53.3)	(47.8)
Adjusted EBITDA from unconsolidated affiliates, net	95.6	80.3	61.1	95.6	80.3
Change in fair value of commodity inventory-related derivative contracts	(18.3)	2.2	14.1	(18.3)	2.2
Significant transaction and environmental-related costs and other items	3.1	12.4	11.6	3.1	12.4
Adjusted EBITDA	$420.1	$395.4	$455.6	$424.3	$398.3

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Segment Results

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

Crestwood Equity and Crestwood Midstream	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics
Revenues	$ 946.7	$ 17.1	$ 2,690.3
Intersegment revenues	192.4	10.5	(202.9)
Costs of product/services sold	767.0	0.2	2,362.2
Operations and maintenance expenses	71.7	3.3	50.8
Loss on long-lived assets, net	(3.0)	—	(27.3)
Earnings from unconsolidated affiliates, net	22.5	30.8	—
EBITDA for the year ended December 31, 2018	$ 319.9	$ 54.9	$ 47.1
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)
Crestwood Equity			
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)

Segment Results

Below is a discussion of the factors that impacted EBITDA by segment for the years ended December 31, 2018, 2017 and 2016.

Gathering and Processing

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

EBITDA for our gathering and processing segment increased by approximately $41.1 million for the year ended December 31, 2018 compared to 2017. Our gathering and processing segment's costs of product/services sold decreased by approximately $713.8 million during the year ended December 31, 2018 compared to 2017, while our revenues only decreased by $683.6 million year over year.

Our gathering and processing segment's revenues and product costs were impacted by the modified retrospective adoption of ASU 2014-09, Revenue from Contracts with Customers, during the year ended December 31, 2018, which decreased its revenues and product costs by approximately $1,015.4 million and $1,026.8 million, respectively. Also impacting our gathering and processing segment's EBITDA during the year ended December 31, 2018 compared to 2017, were lower revenues and product costs of approximately $30.2 million and $21.8 million, respectively, as a result of the deconsolidation of Crestwood New Mexico Pipeline LLC (Crestwood New Mexico) in 2017.

The remaining increase in our gathering and processing segment's revenues and costs of product/services sold of approximately $362.0 million and $334.8 million, respectively, during the year ended December 31, 2018 compared to 2017, was primarily driven by our Arrow operations. Natural gas volumes and water volumes gathered by our Arrow system increased by 40% and 30%, respectively, during the year ended December 31, 2018 compared to 2017. These favorable variances were driven by increased producer activity and expanded capacity on our Arrow system. In addition, the Bear Den processing plant was placed into service in late 2017, which increased natural gas volumes gathered and processed by the Arrow system. Arrow also experienced higher average prices on its agreements under which it purchases and sells crude oil as a result of the increase in crude oil prices in 2018 compared to 2017.

Our gathering and processing segment's operations and maintenance expenses increased by approximately $3.3 million during the year ended December 31, 2018 compared to 2017, primarily due to the increase in volumes related to our Arrow operations described above.

Our gathering and processing segment's EBITDA for the year ended December 31, 2018 includes a loss on long-lived assets of approximately $3.0 million, primarily related to the retirement and/or disposal of certain of our Arrow and Granite Wash gathering and processing assets.

Our gathering and processing segment's EBITDA was favorably impacted by a net increase in earnings from unconsolidated affiliates of approximately $3.6 million during the year ended December 31, 2018 compared to 2017. Equity earnings from our Jackalope equity investment increased by approximately $7.6 million primarily due to a 73% and 57% increase in its gathering and processing volumes during 2018 compared to 2017 resulting from increased producer activity on its system. Our equity earnings from our Crestwood Permian equity investment decreased by approximately $4.0 million during 2018 compared to 2017. Pursuant to the Crestwood Permian limited liability company agreement, we were allocated 100% of the equity earnings from Crestwood New Mexico through June 30, 2018. Subsequent to June 30, 2018, our equity earnings from Crestwood New Mexico were allocated based on our ownership percentage in Crestwood Permian, which is currently 50%.

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

EBITDA for CEQP'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 2016, 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 its revenues as a result of the restructuring of its contracts with Chesapeake effective January 1, 2017. Jackalope and Chesapeake replaced the cost-of-

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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.

Storage and Transportation

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

EBITDA for our storage and transportation segment increased by approximately $43.6 million during the year ended December 31, 2018 compared to 2017. The comparability of our storage and transportation segment's EBITDA year over year was impacted by a $57 million loss on contingent consideration recorded during 2017 related to our Stagecoach Gas joint venture as further described below.

During 2017 and early 2018, several of COLT's firm rail loading agreements expired that provided COLT with take-or-pay revenues at rates that were higher than spot market rates. As a result, COLT's revenues decreased by approximately $16.3 million during the year ended December 31, 2018 compared to 2017 despite its rail loading volumes increasing by 28% year-over-year. The increase in volumes was due to higher demand for rail loading services resulting from higher Bakken crude oil production and higher basis differentials between Bakken and the U.S. western and eastern markets.

Our storage and transportation segment's EBITDA was also impacted by a net increase in earnings from unconsolidated affiliates during the year ended December 31, 2018 compared to 2017. Earnings from our Stagecoach Gas equity investment increased by approximately $4.0 million during 2018 compared to 2017, primarily due to our share of Stagecoach Gas' equity earnings increasing from 35% to 40% effective July 1, 2018. Effective July 1, 2019, our equity earnings from Stagecoach Gas will be allocated based on our ownership percentage, which is currently 50%. Partially offsetting this increase were lower equity earnings from our Tres Holdings equity investment of approximately $2.2 million due to higher repair and maintenance costs at the joint venture.

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

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. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6 for a further discussion of the deconsolidation of our NE S&T assets.

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We experienced lower operations and maintenance expenses of approximately $17.2 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. 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.

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.

Marketing, Supply and Logistics

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

EBITDA for our marketing, supply and logistics segment increased by approximately $76.8 million during the year ended December 31, 2018 compared to 2017. The comparability of our marketing, supply and logistics segment's results was impacted by the sale of certain of our assets during 2018 and 2017 and approximately $121.0 million of goodwill, intangible assets and property, plant and equipment impairments recorded during 2017, all of which are further described below.

During the year ended December 31, 2018, we recorded a $26.9 million loss on long-lived assets related to the sale of our West Coast facilities in October 2018, which also resulted in lower revenues and costs of product/services sold of approximately $81.4 million and $71.4 million in 2018 compared to 2017. During the year ended December 31, 2017, we recorded a $33.6 million gain related to the sale of US Salt, which also resulted in lower revenues and costs of product/services sold of approximately $59.8 million and $34.9 million during the year ended December 31, 2018 compared to 2017.

EBITDA for our marketing, supply and logistics segment (excluding the impacts from the sale of our West Coast and US Salt assets described above) was also impacted by an increase in its revenues and costs of product/services sold of approximately $614.3 million and $574.9 million during the year ended December 31, 2018 compared to 2017.

Our crude and natural gas marketing operations experienced an increase in its revenues and product costs of approximately $564.5 million and $557.6 million. These increases were driven by higher crude marketing volumes due to increased marketing activity surrounding our crude-related operations.

The remaining $32.6 million increase in our revenues (net of costs of product/services sold) during the year ended December 31, 2018 compared to 2017 was driven by our NGL marketing and logistics operations. Included in our costs of product/services sold was a gain of $29.6 million and a loss of $31.2 million during the years ended December 31, 2018 and 2017, respectively. Of the $29.6 million gain in 2018, approximately $18.3 million related to the change in fair value of commodity inventory-related derivative contracts that had not yet settled in cash at December 31, 2018. The remaining increase in our revenues and costs of product/services sold of our NGL marketing and logistics operations was primarily the result of our ability to capture more marketing opportunities to purchase and sell NGLs given the unusually cold weather during 2018. In addition, we experienced increased demand for trucking, rail, storage and terminal services as a result of an expanded US NGL supply base and market dislocations caused by increased NGL supplies from various high growth regions and regional pipeline outages.

During the year ended December 31, 2018, our marketing, supply and logistics segment's operations and maintenance expenses decreased by approximately $12.6 million compared to 2017, primarily due to the sale of our West Coast and US Salt assets described above, in addition to efforts to realign certain of its operations.

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 a loss of $31.2 million and $7.8 million during the years ended December 31, 2017 and 2016, respectively, related to our commodity-based derivative contracts. These changes in the fair value of our derivative contracts resulted from higher average NGL prices during 2017 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 Bakken crude-related operations resulting from higher Bakken crude oil production and higher basis differentials between Bakken and the U.S. western and eastern markets.

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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Other EBITDA Results

General and Administrative Expenses. During the year ended December 31, 2018, our general and administrative costs decreased compared to 2017, while we experienced an increase in these costs during 2017 compared to 2016. During the years ended December 31, 2018 and 2017, we incurred approximately $1.3 million and $2.2 million of transactional and other general and administrative costs related primarily to the realignment initiatives we undertook related to realigning our Marketing, Supply and Logistics operations. In addition, our unit-based compensation charges increased by $3.0 million from 2017 to 2018 and by $6.3 million from 2016 to 2017 due to higher average awards outstanding under our long-term incentive plans.

Items not affecting EBITDA include the following:

Depreciation, Amortization and Accretion Expense. During the year ended December 31, 2018, our depreciation, amortization and accretion expense decreased compared to 2017 and 2016, primarily due to the sale of our West Coast assets and US Salt operations during 2018 and 2017, respectively, and the deconsolidation of our Crestwood New Mexico operations in 2017. For a further discussion of these transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Notes 3 and 6.

Interest and Debt Expense, Net. During the year ended December 31, 2018, interest and debt expense, net was relatively flat compared to 2017, while we experienced a decrease of approximately $25.7 million during 2017 compared to 2016. The net decrease was primarily due to repayments of amounts previously outstanding under Crestwood Midstream’s senior notes in 2017 and late 2016 .

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

	Year Ended December 31,		
	2018	2017	2016
Credit facilities	$24.6	$18.6	$18.7
Senior notes	72.5	76.4	99.9
Other debt-related costs	7.1	7.3	7.2
Gross interest and debt expense	104.2	102.3	125.8
Less: capitalized interest	5.0	2.9	0.7
Interest and debt expense, net	$99.2	$99.4	$125.1

Gain (Loss) on Modification/Extinguishment of Debt. During the year ended December 31, 2018, we recognized a loss on modification of debt of approximately $0.9 million in conjunction with amending and restating Crestwood Midstream’s senior secured revolving credit facility. 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 principal amounts previously outstanding under Crestwood Midstream's senior notes due in 2020 and 2022. 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 the principal amounts previously outstanding under Crestwood Midstream’s senior notes due in 2020 and 2022.

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 equity investments 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.

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In October 2018, Crestwood Midstream entered into a Second Amended and Restated Credit Agreement (the Second Amended Credit Agreement). The Second Amended Credit Agreement provides for a five-year $1.25 billion revolving credit facility, which expires in October 2023 and is available to fund acquisitions, working capital and internal growth projects and for general partnership purposes. Interest rates under the Second Amended Credit Agreement were reduced by 0.25%, and the debt covenants under the Second Amended Credit Agreement are materially consistent with those under the previous credit facility. For a further discussion of the Second Amended Credit Agreement, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9. As of December 31, 2018, we had $524.0 million of available capacity under the credit facility considering the most restrictive debt covenants in the credit agreement. As of December 31, 2018, 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.

Cash Flows

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

	Year Ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	$253.6	$255.9	$346.1
Net cash provided by (used in) investing activities	(241.2)	38.7	867.2
Net cash provided by (used in) financing activities	3.5	(294.9)	(1,212.2)

Operating Activities

Our operating cash flows decreased by $2.3 million during the year ended December 31, 2018 compared to 2017. We experienced higher revenues and costs primarily from our gathering and processing segment's Arrow operations of $362.0 million and $334.8 million, respectively, and higher revenues (net of costs of product/services sold) from our marketing, supply and logistics segment's NGL marketing and logistics operations of approximately $32.6 million . Offsetting these higher revenues and costs was a $16.3 million decrease in operating revenues from our COLT Hub operations and a net cash outflow from working capital requirements of approximately $47.2 million. For a further discussion of our segments' results, see Results of Operations above.

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 resulting from 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.

Investing Activities

Capital Expenditures. 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 2019, we anticipate growth capital expenditures of approximately $275 million to $325 million, which includes contributions to our equity investments related to their capital projects. In addition, we expect to spend between approximately $20 million to $25 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 2019 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 flows and earnings. The following table summarizes our capital expenditures for the year ended December 31, 2018 (in millions):

Growth capital	$267.3
Maintenance capital	20.6
Other(1)	17.6
Purchases of property, plant and equipment	$305.5

(1) Represents 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, 2018, 2017 and 2016:

- In October 2018, we sold our West Coast facilities to a third party for net proceeds of approximately $70.5 million;
- 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; and
- During the years ended December 31, 2018, 2017 and 2016, we contributed approximately $64.4 million, $58.0 million and $12.4 million, respectively, to our equity investments to fund their expansion projects and their operating activities.

Financing Activities

Significant items impacting our financing activities during the years ended December 31, 2018, 2017 and 2016 included the following:

Equity Transactions

- In December 2017, Crestwood Niobrara redeemed 100% of the outstanding Series A 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 Series A-2 preferred units to CN Jackalope Holdings LLC (Jackalope Holdings). For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 12. We began making distributions to Jackalope Holdings on its Series A-2 preferred units in April 2018, and during the year ended December 31, 2018, we distributed approximately $9.9 million to our non-controlling partner. During each of the years ended December 31, 2017 and 2016, we distributed approximately $15.2 million to GE for its non-controlling interest in Crestwood Niobrara;
- During the year ended December 31, 2018, our distributions to partners increased by approximately $3.2 million compared to 2017 due to an increase our common unitholders. Our distributions to partners decreased by 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 distribution paid in May 2016;
- During the years ended December 31, 2018 and 2017, we made cash distributions of approximately $60.1 million and $15 million to our preferred unitholders. Prior to September 30, 2017, we paid quarterly distributions to our preferred unitholders by issuing additional preferred units;
- During the year ended December 31, 2017, we received net proceeds of approximately $15.2 million from the issuance of CEQP common units; and

- During the year ended December 31, 2018, our taxes paid for unit-based compensation vesting increased by approximately $1.9 million compared to 2017, and increased by approximately $4.7 million during 2017 compared to 2016, primarily due to higher vesting of unit-based compensation awards.

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Debt Transactions

- During the year ended December 31, 2018, our debt-related transactions resulted in net borrowings of approximately $253.4 million compared to net repayments of approximately $76.3 million in 2017 and net repayments of $974.5 million in 2016. During 2017 and 2016, we redeemed all amounts previously outstanding under Crestwood Midstream's senior notes due in 2020 and 2022. During 2017, we issued $500 million of senior unsecured notes due in 2025. 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, 2018 (in millions):

	Less than 1 Year	1-3 Years	3-5 Years	Thereafter	Total
Long-term debt:					
Principal	$0.9	$0.4	$1,278.4	$ 500.0	$1,779.7
Interest(1)	100.3	198.5	162.3	35.9	497.0
Standby letters of credit	68.0	—	—	—	68.0
Future minimum payments under operating leases(2)	22.3	32.5	15.7	10.7	81.2
Future minimum payments under capital leases(2)	3.0	6.5	1.9	—	11.4
Asset retirement obligations	—	—	—	27.6	27.6
Fixed price commodity purchase commitments(3)	784.3	109.7	—	—	894.0
Purchase commitments and other contractual obligations(4)	79.0	—	—	—	79.0
Total contractual obligations	$1,057.8	$347.6	$1,458.3	$ 574.2	$3,437.9

(1) $578.2 million of our long-term debt is variable interest rate debt at the Alternate Base rate or Eurodollar rate plus an applicable spread. These rates plus their applicable spreads were between 4.63% and 6.75% at December 31, 2018. 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 gathering and processing 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, 2018, 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.

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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, 2018, the carrying value and fair value of our fixed rate debt instruments was approximately $1.2 billion and $1.1 billion, respectively. As of December 31, 2017, both the carrying value and fair value of our fixed rate debt instruments was approximately $1.2 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, 2018, we had obligations totaling $578.2 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 our credit facility were to fluctuate by 1% from the rate as of December 31, 2018, our annual interest expense would have changed by approximately $5.8 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 (MS&L segment); (ii) NGLs under certain of our percentage-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, 2018, 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, 2018 were assets of $34.7 million and liabilities of $5.8 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 $7.0 million change in the market value of these contracts as there were approximately 2 MMBbls of net unbalanced positions at December 31, 2018. Inventory positions of approximately 2 MMBbls would substantially offset this theoretical change at December 31, 2018.

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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, 2018, 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, 2018.

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 2018 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 of their General Partners, Crestwood Equity and Crestwood Midstream assessed the effectiveness of their respective internal control over financial reporting as of December 31, 2018. 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, 2018, 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 22, 2019, on the effectiveness of our internal control over financial reporting, which is included herein.

Item 9B. Other Information

None.

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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 eight 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	64	President, Chief Executive Officer and Director
J. Heath Deneke	45	Executive Vice President, Chief Operating Officer
Robert T. Halpin	35	Executive Vice President, Chief Financial Officer
Steven M. Dougherty	46	Senior Vice President, Chief Accounting Officer
Joel C. Lambert	50	Senior Vice President, General Counsel and Chief Compliance Officer
William H. Moore	39	Senior Vice President, Strategy and Corporate Development
Alvin Bledsoe	70	Director
Warren H. Gfeller	66	Director
Janeen S. Judah	59	Director
David Lumpkins	64	Director
Gary D. Reaves	39	Director
John J. Sherman	63	Director
John W. Somerhalder II	63	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. Mr. Phillips holds a 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 Executive Vice President, Chief Operating Officer in August 2017. 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 served in 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.

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.

Janeen S. Judah was appointed as a director of our general partner in November 2018. She currently serves as a Director at Patterson-UTI Energy, Inc. Ms. Judah previously held numerous leadership positions at Chevron Corporation (Chevron), including general manager for Chevron's Southern Africa business unit, president of Chevron Environmental Management Company and general manager of Reservoir and Production Engineering for Chevron Energy Technology Company. Ms. Judah was appointed to the board due to her more than 35 years of operational and managerial experience within the energy industry. Ms. Judah holds Bachelor of Science and Masters of Science degrees in petroleum engineering from Texas A&M University, a Masters of Business Administration from The University of Texas of the Permian Basin and a Juris Doctorate from the University of Houston Law Center. Ms. Judah's diverse energy experience as well as her environmental expertise adds significant value to 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 our board of directors.

Gary D. Reaves was appointed to the board of our general partner in January 2019. Mr. Reaves is a Managing Director at First Reserve, a leading global private equity investment firm exclusively focused on energy, which he joined in 2006. Prior to joining First Reserve, he held roles in the Global Energy Group at UBS Investment Bank and Howard Frazier Barker Elliott, Inc. Mr. Reaves 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. Mr. Reaves holds a B.B.A from The University of Texas.

John J. Sherman has served as a director of our general partner since March 2001 and previously served as a director of CMLP GP. 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.

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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.

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, Janeen Judah, 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), Janeen Judah and David Lumpkins. 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

The members of the compensation committee are Warren Gfeller (Chairman) and Alvin Bledsoe. 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. Our compensation committee charter may be found on our website at www.crestwoodlp.com.

Conflicts Committee

The members of the conflicts committee are John Somerhalder II (Chairman) and David Lumpkins. Our general partner has established a conflicts committee to review specific matters which the board of directors believes may involve conflicts of interest. 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

The members of the finance committee are David Lumpkins (Chairman) and Warren Gfeller. 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.

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Sustainability Committee

The members of the sustainability committee are Janeen Judah (Chairman) and John Somerhalder II. Our general partner has established a sustainability committee to provide oversight of our sustainability initiatives and to ensure that environmental, social and governance risks are incorporated into our long-term business strategy. The sustainability committee will also oversee the development of our sustainability strategy, as well as review and recommend to the board for approval of any sustainability reporting and disclosure.

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.

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.

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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, 2018, 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 2018 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;
- Steven M. Dougherty, our Senior Vice President and Chief Accounting Officer; and
- Joel C. Lambert, our Senior Vice President, General Counsel and Chief Compliance 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.

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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 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 reviews and ratifies all aspects of executive compensation based on the reports and recommendations 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 peer group and published compensation survey data. For the CEO, in fiscal 2018 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 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

Willis Towers Watson was engaged to serve 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 based on its extensive experience in providing executive compensation advice, including specific experience in the oil and gas industry. For fiscal 2018, Willis Towers Watson 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 consultant in order to make compensation decisions. The compensation committee has assessed the independence of the compensation consultant and has concluded that the compensation consultant’s 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, Willis Towers Watson, with the assistance of management, proposed certain peer group companies for our compensation committee’s review.

After discussion with Willis Towers Watson 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 2018 executive compensation analyses.

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Andeavor Logistics LP	Magellan Midstream Partners, L.P.
Boardwalk Pipeline Partners LP	Midcoast Energy Partners, L.P.
Buckeye Partners, L.P.	MPLX, LP
DCP Midstream Partners, LP	SemGroup Corporation
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	Western Gas Partners, LP

Willis Towers Watson 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.

The compensation committee strives to maintain average total compensation for our executive officers between the 50th and 75th percentile of the peer group with target base and short-term incentives at the 50th percentile and target long-term incentives at the 75th percentile.

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 increases for our NEOs effective January 1, 2018. Accordingly, the annual base salaries were increased as follows: Mr. Phillips ($750,000), Mr. Halpin ($450,000), Mr. Dougherty ($410,000), Mr. Lambert ($410,000) and Mr. Moore ($385,000). Mr. Deneke's base salary was increased in July 2017 in connection with an amendment to his employment agreement and remain unchanged in 2018.

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.

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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 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 2018 were determined based on our achievement of compensation committee approved key performance indicators (KPIs) and a board discretionary component. The KPIs for fiscal 2018 were Distributable Cash Flow Per Common Unit, Adjusted EBITDA, Operational and Administrative Expense, 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.

2018 Annual Incentive Awards KPIs	Weighting	Target
Distributable Cash Flow Per Common Unit	30 %	$2.95
Adjusted EBITDA	30 %	$405.0
Operational and Administrative Expense	10 %	$255.0
Relative Total Shareholder Return	10 %	100 %
Total Recordable Incident Rate	5 %	1.6
At-Fault Vehicle Incident Rate	5 %	2.1
Lost Time Injury Rate	5 %	0.8
NOV/NOE Count	5 %	20
	100 %	—

Based on the company’s KPI achievement, the actual annual incentive bonus pool for fiscal 2018 was established at 116% 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 2018, each NEO received the highest performance rating of “1” which increased the actual percentage for such individuals to 150% of target, which is equivalent to the company-wide target payout for “1” performance ratings.

The 2018 bonus payouts were as follows:

Name	2018 Base Salary ($)	Target Bonus ($)	Percentage of Target Bonus	Total ($)
Robert G. Phillips	750,000	750,000	150%	1,125,000
J. Heath Deneke	525,000	656,250	150%	984,375
Robert T. Halpin	450,000	450,000	150%	675,000
William H. Moore	385,000	385,000	150%	577,500
Steven M. Dougherty	410,000	328,000	150%	492,000
Joel C. Lambert	410,000	328,000	150%	492,000

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. No project completion bonus awards were made to our NEOs in 201.

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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 2018, awards consisted of grants of restricted common units which vest based upon continued service. 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 annual 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 equity awards at the 75th percentile of market data, the annual target long-term incentive awards were increased in 2018 as follows: Mr. Phillips (300%), Messrs. Halpin and Deneke (275%) and Messrs. Moore, Dougherty and Lambert (225%). Accordingly, the following annual restricted unit awards were made to our NEOs in 2018:

Name	Target Equity Percentage	2018 Restricted Units Awarded (#)	Value at Grant Date ($)
Robert G. Phillips	300%	87,209	2,215,109
J. Heath Deneke	275%	55,959	1,421,359
Robert T. Halpin	275%	47,965	1,218,311
William H. Moore	225%	41,328	1,049,731
Steven M. Dougherty	225%	35,756	908,202
Joel C. Lambert	225%	35,756	908,202

In addition based on survey and other compensation data provided to the compensation committee by Willis Towers Watson, the compensation committee determined that there was a deficiency between total current executive compensation and the target of the 75th percentile of market data. Accordingly, the compensation committee approved a one-time “cliff” restricted unit award to each of our NEOs, except Mr. Deneke. Mr. Deneke was excluded because he received a cliff award in July 2017 in connection with an amendment to his employment agreement. These cliff awards vest in full three years from the grant date based on the continued service of the NEO. The following table summarizes the 2018 “cliff awards” to the NEOs:

Name	2018 Cliff Restricted Units Awarded (#)	Value at Grant Date ($)
Robert G. Phillips	75,000	1,905,000
Robert T. Halpin	75,000	1,905,000
William H. Moore	50,000	1,270,000
Steven M. Dougherty	50,000	1,270,000
Joel C. Lambert	50,000	1,270,000

In addition to the annual restricted unit grants, our NEOs are eligible to receive performance phantom unit awards. No performance phantom units were awarded in fiscal 2018, but on February 12, 2019, each of our NEOs received a grant of performance phantom units. These 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. 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 full performance metrics and value of the 2019 performance phantom units awarded to our NEOs will be disclosed in our 2019 Form 10-K.

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 in 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 2018."

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.

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, 2018.

Members of the Compensation Committee

Warren Gfeller

Alvin Bledsoe

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Summary Compensation Table for Fiscal 2018

The following table sets forth the cash and non-cash compensation earned by our NEOs for the fiscal years ended December 31, 2018, 2017 and 2016.

Name and Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Unit Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)(2)	Total ($)
Robert G. Phillips	2018	747,102	—	4,120,109	1,125,000	17,388	6,009,599
President, Chief Executive	2017	674,650	1,000	4,702,856	961,875	44,439	6,384,820
Officer and Director	2016	655,000	—	1,589,964	655,000	17,088	2,917,052
J. Heath Deneke Executive	2018	525,000	10,000	1,421,359	984,375	16,470	2,957,204
Vice President and Chief	2017	504,375	11,000	4,434,069	740,036	16,387	5,705,867
Operating Officer	2016	475,000	100,000	1,062,601	427,500	15,780	2,080,881
Robert T. Halpin Executive	2018	448,538	—	3,123,311	675,000	16,344	4,263,193
Vice President, Chief	2017	412,000	1,000	2,091,101	554,040	16,344	3,074,485
Financial Officer	2016	400,000	115,000	860,017	360,000	15,744	1,750,761
William H. Moore	2018	384,058	—	2,319,731	577,500	16,254	3,297,543
Senior Vice President,	2017	360,500	201,000	1,385,905	503,550	16,254	2,467,209
Strategy and Corporate Development	2016	350,000	100,000	713,284	350,000	15,654	1,528,938
Steven M. Dougherty	2018	409,087	—	2,178,202	492,000	16,470	3,095,759
Senior Vice President,	2017	386,250	1,000	1,412,505	429,840	16,470	2,246,065
Chief Accounting Officer	2016	375,000	—	530,990	300,000	15,780	1,221,770
Joel C. Lambert Senior Vice President, General Counsel and Chief Compliance Officer	2018	409,087	—	2,178,202	492,000	16,614	3,095,903

(1) The material terms of our outstanding LTIP awards 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. 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 2018 consisted of the following:

Name	401(k) Matching Contributions ($)	Group Term Life Insurance ($)	Total ($)
Robert G. Phillips	16,200	1,188	17,388
J. Heath Deneke	16,200	270	16,470
Robert T. Halpin	16,200	144	16,344
William H. Moore	16,200	54	16,254
Steven M. Dougherty	16,200	270	16,470
Joel C. Lambert	16,200	414	16,614

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Grants of Plan-Based Awards Table for Fiscal 2018

The following table provides information concerning each grant of an award made to our NEOs during fiscal 2018.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)				
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	All Other Unit Awards (#)(2)	Grant Date Fair Value of Unit and Option Awards ($)(3)
Robert G. Phillips	01/08/18				87,209	2,215,109
	01/08/18				75,000	1,905,000
		300,000	750,000	1,125,000		
J. Heath Deneke	01/08/18				55,959	1,421,359
		262,500	656,250	984,375		
Robert T. Halpin	01/08/18				47,965	1,218,311
	01/08/18				75,000	1,905,000
		180,000	450,000	675,000		
William H. Moore	01/08/18				41,328	1,049,731
	01/08/18				50,000	1,270,000
		154,000	385,000	577,500		
Steven M. Dougherty	01/08/18				35,756	908,202
	01/08/18				50,000	1,270,000
		164,000	328,000	492,000		
Joel C.Lambert	01/08/18				35,756	908,202
	01/08/18				50,000	1,270,000
		164,000	328,000	492,000		

(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 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. In addition, represents grants of one-time "cliff " restricted unit award, which vest three years from the grant date.

(3) Unit award amounts reflect the aggregate grant date fair value of unit awards granted during 2018 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.

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 (other than Mr. Deneke's Executive Employment Agreement described below), 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

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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.

Under the terms of the Second Amended and Restated Employment Agreement (the Deneke Employment Agreement, if Mr. Deneke's employment is terminated by 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, 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 Executive Employment Agreements, the Deneke Employment Agreement and the Omnibus Amendment 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 Amendment, each of which is incorporated by reference herein as an exhibit to this report.

Outstanding Equity Awards at 2018 Fiscal Year-End

The following table summarizes the outstanding equity awards as of the end of Fiscal 2018 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.

	UNIT AWARDS	
Name	Number of Units That Have Not Vested (#)(1)(2)	Market Value of Units That Have Not Vested ($)(3)
Robert G. Phillips	340,406	9,874,697
J. Heath Deneke	228,975	6,530,409
Robert T. Halpin	202,734	5,773,351
William H. Moore	146,543	4,176,313
Steven M. Dougherty	139,211	3,971,677
Joel C. Lambert	139,211	3,971,677

(1)

Mr. Phillips' restricted units vest as follows: 25,636 units vest on January 5, 2019, 29,069 units vest on January 8, 2019, 37,884 units vest on January 15, 2019, 25,636 units vest on January 5, 2020, 29,070 units vest on January 8, 2020 and 104,070 units vest on January 8, 2021. Mr. Phillips' 89,041 phantom performance units vest on February 15, 2020. Mr. Deneke's restricted units vest as follows: 20,189 units vest on January 5, 2019, 18,653 units vest on January 8, 2019, 22,894 units vest on January 15, 2019, 1,476 units vest on June 6, 2019, 20,189 units vest on January 5, 2020, 18,653 units vest on January 8, 2020, 75,000 units vest on June 30, 2020 and 18,653 units vest on January 8, 2021. Mr. Deneke's 33,268 phantom performance units vest on February 15, 2020. Mr. Halpin's restricted units vest as follows: 16,177 units vest on January 5, 2019, 15,988 units vest on January 8, 2019, 19,279 units vest on January 15, 2019, 738 units vest on June 6, 2019, 16,178 units vest on January 5, 2020, 15,988 units vest on January 8, 2020 and 90,989 units vest on January 8, 2021. Mr. Halpin's 27,397 phantom performance units vest on February 15, 2020. Mr. Moore's restricted units vest as follows: 9,785 units vest on January 5, 2019, 13,776 units vest on January 8, 2019, 12,146 units vest on January 15, 2019, 2,951 units vest on June 6, 2019, 9,785 units vest on January 5, 2020, 13,776 units vest on January 8, 2020 and 63,776 units vest on January 8, 2021. Mr. Moore's 20,548 phantom performance

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units vest on February 15, 2020. Mr. Dougherty's restricted units vest as follows: 10,127 units vest on January 5, 2019, 11,918 units vest on January 8, 2019, 12,652 units vest on January 15, 2019, 10,128 units vest on January 5, 2020, 11,919 units vest on January 8, 2020 and 61,919 units vest on January 8, 2021. Mr. Dougherty's 20,548 phantom performance units vest on February 15, 2020. Mr. Lambert's restricted units vest as follows: 10,127 units vest on January 5, 2019, 11,918 units vest on January 8, 2019, 12,652 units vest on January 15, 2019, 10,128 units vest on January 5, 2020, 11,919 units vest on January 8, 2020 and 61,919 units vest on January 8, 2021. Mr. Lambert's 20,548 phantom performance units vest on February 15, 2020. The above vesting schedule does not include the unitized accrued distributions on the performance phantom unit grants.

(2) Does not includes unitization of the accrued distributions on the performance phantom unit grants.

(3) Market value for CEQP units based on the NYSE closing price of $27.91 on December 31, 2018.

Units Vested During Fiscal 2018

The following table provides information regarding restricted units vesting during Fiscal 2018 for each of the NEOs. Value realized on 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.

	UNIT AWARDS	
Name	Number of Units Acquired On Vesting (#)	Value Realized on Vesting ($)
Robert G. Phillips	104,974	2,803,292
J. Heath Deneke	66,625	1,786,681
Robert T. Halpin	52,380	1,401,394
William H. Moore	27,460	752,093
Steven M. Dougherty	41,405	1,105,693
Joel C. Lambert	41,483	1,107,791

Pension Benefits during Fiscal 2018

We do not offer any pension benefits.

Non-qualified Deferred Compensation during Fiscal 2018

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.

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 2018

Under the terms of the Executive Employment Agreements, other than Mr. Deneke's Executive Employment Agreement described below, 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.

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Under the terms of Mr. Deneke's Executive Employment Agreement, if Mr. Deneke's employment is terminated by 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.
Under the terms of the Executive Employment Agreements (other than Mr. Phillips), if the named executive officer 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.

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, 2018.

Name	Cash Severance ($)(1)	Accelerated Vesting of Restricted Units ($)(2)	Benefit Continuation ($)(3)	Total ($)
Robert G. Phillips	5,455,313	9,500,731	9,413	14,965,457
J. Heath Deneke	2,804,411	6,390,692	25,726	9,220,829
Robert T. Halpin	2,159,040	5,658,306	25,720	7,843,066
William H. Moore	1,851,050	4,090,015	25,726	5,966,791
Steven M. Dougherty	1,765,840	3,885,379	25,726	5,676,945
Joel C. Lambert	1,791,840	3,885,379	26,075	5,703,294

(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. The cash severance payable to each of Messrs. Deneke, Halpin, Moore, Dougherty and Lambert would increase to $4,206,617, $3,238,560, $2,776,575, $2,648,760, and $2,687,760, 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 performance 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 $27.91 for CEQP units on December 31, 2018. This value does not reflect the unitization of the accrued distributions on the performance phantom unit grants.

(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.

Under the terms of Mr. Deneke's Executive Employment Agreement, if on or before July 1, 2019, there is a Change in Control 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 $27.91 for CEQP units on December 31, 2018, is $3,488,750.

On February 22, 2018, the Executive Employment Agreements for Messrs. Phillips, Halpin, Moore, Dougherty and Lambert 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, and 75,000 units to Messrs. Moore, Dougherty and Lambert, respectively. These units shall be fully vested on their issuance date. The value of such restricted units, based on the NYSE closing price of $27.91 for CEQP units on December 31, 2018, is $4,186,500 for Mr. Phillips, $2,791,000 for Mr. Halpin and $2,093,250 for Messrs Moore, Dougherty and Lambert, respectively.

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Director Compensation Table for Fiscal 2018

The following table sets forth the cash and non-cash compensation for Fiscal 2018 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	120,000	101,138	1,196(3)	222,334
Michael France(2)	—	101,138	—	101,138
Warren Gfeller	130,000	101,138	—	231,138
Janeen Judah	19,800	24,980	—	44,780
David Lumpkins	120,000	101,138	—	221,138
John Sherman	100,000	101,138	—	201,138
John Somerhalder II	120,000	101,138	12,396(3)	233,534

(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 the grant date. As of December 31, 2018, our non-employee directors held the following restricted unit awards: Mr. France, Mr. Gfeller, Mr. Lumpkins and Mr. Sherman each held 3,875 restricted units. Mr. Bledsoe and Mr. Somerhalder deferred their unit awards pursuant to the Non-Qualified Deferred Compensation Plan.

(2) Mr. France resigned from the board of directors on January 22, 2019.

(3) Mr. Somerhalder deferred his equity awards and fees pursuant to the Non-Qualified Deferred Compensation Plan. Mr. Bledsoe deferred his equity awards pursuant to the Non-Qualified Deferred Compensation Plan.

Compensation of Directors during Fiscal 2018

Officers of our general partner who also serve as directors do not receive additional compensation. Each director receives 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 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 $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.

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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 2018 total taxable cash and equity compensation (again, to the extent taxed to the employee in 2018), 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, 2018. We included all employees, whether employed on a full-time, part-time, temporary or seasonal basis. As of December 31, 2018, we employed 843 such persons. We annualized the compensation for any employees that were not employed for all of 2018 (not including seasonal or temporary 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 2018 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 2018 compensation was as follows:

Name	Year	Salary	Bonus	Stock Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Median Employee	2018	$87,053	$—	$—	$—	$—	$87,053

With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2018 Summary Compensation Table included in this Annual Report, which was $6,009,599. Our 2018 ratio of chief executive officer total compensation to our median employee's total compensation is reasonably estimated to be 69:1.

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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, 2019, 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.

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
Crestwood Gas Services Holdings LLC[2][3][4]	9,985,462		13.9%
Crestwood Holdings LLC[2][3]	7,484,449		10.4%
Harvest Fund Advisors LLC.[5]	3,964,264		5.5%
Alvin Bledsoe[6]	37,199		*
J. Heath Deneke	303,672		*
Steven M. Dougherty	190,743		*
Warren H. Gfeller	48,414		*
Robert T. Halpin	274,010		*
Janeen S. Judah	4,329		*
Joel C. Lambert	174,532		*
David Lumpkins	38,121		*
William H. Moore	178,555		*
Robert G. Phillips	446,668		*
Gary D. Reaves	3,582		
John J. Sherman	3,227,913		4.5%
John W. Somerhalder II[6]	18,627		*
Directors and executive officers as a group (13 persons)	4,946,365	(7)	6.9%

* 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) 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.
(3) Common units owned by Crestwood Gas Services Holdings LLC and Crestwood Holdings LLC are pledged as collateral under the Crestwood Holdings term loan.
(4) 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.

(5) Based on Schedule 13G filed by Harvest Fund Advisors LLC on February 14, 2019. The address of Harvest Fund Advisors LLC is 100 W. Lancaster Avenue, Suite 200, Wayne, PA 19087.

(6) Includes 10,588 restricted units held in the Crestwood Nonqualified Deferred Compensation Plan.

(7) Excludes 449,613 performance phantom units granted to our executive officers pursuant to the Crestwood Equity Long-Term Incentive 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 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 contributed to Crestwood Permian the first $151 million of capital cost required to fund the expansion of the Delaware Basin assets, including a new processing plant located in Orla, Texas and associated pipelines (Orla processing plant), which went into service in July 2018. We received 100% of the available cash flow generated by Crestwood New Mexico through June 30, 2018. Beginning with the third quarter of 2018, both 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 party 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;

- any applicable generally accepted accounting practices or principles; and

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- 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 party 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 party 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, 2018. The following table summarizes the fees for professional services rendered by Ernst & Young LLP for the years ended December 31, 2018 and 2017 (in millions).

	2018	2017
Audit-related fees(1)	$1.8	$2.0
All other fees(2)	0.2	0.2
Total	$2.0	$2.2

(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 2018. 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)
3.22	Third Amendment to the Fifth Amended and Restated Agreement of Limited Partnership of Crestwood Equity Partners LP entered into and effective as of May 30, 2018 (incorporated by reference to Exhibit 3.1

	to Crestwood Equity Partners LP's Form 8-K filed on June 4, 2018)
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 (incorporated herein by reference to Exhibit 4.4 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018)

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Exhibit Number	Description
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)
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 (incorporated herein by reference to Exhibit 4.9 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018)
4.10	Registration Rights Agreement, dated December 28, 2017, by and among Crestwood Equity Partners LP and CN Jackalope Holdings, LLC (incorporated herein by reference to Exhibit 4.10 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018)
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)
**4.13	Supplemental Indenture dated as of October 22, 2018, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee
*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 (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018)
*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)

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Exhibit Number	Description
*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)
*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)

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Exhibit Number	Description
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)
*10.27	Crestwood Equity Partners LP 2018 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed with the Commission on May 16, 2018).
*10.28	Crestwood Equity Partners LP Employee Unit Purchase Plan. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K, filed with the Commission on August 24, 2018)
*10.29	Form of Crestwood Equity Partners LP's Executive Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 10-Q filed November 1, 2018)
*10.30	Form of Crestwood Equity Partners LP's Non-Executive Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018)
*10.31	Form of Crestwood Equity Partners LP's Director Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.3 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018)
*10.32	Form of Crestwood Equity Partners LP's Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018)
*10.33	Second Amended and Restated Credit Agreement, dated as of October 18, 2018, 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 Equity Partners LP's Form 8-K filed on October 18, 2018)
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 - Stagecoach Gas Services LLC
**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

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Exhibit Number	Description
**99.1	Financial Statements for Stagecoach Gas Services LLC as of December 31, 2018 and 2017 and for the years ended December 31, 2018 and 2017 and for the period from June 3, 2016 to December 31, 2016 (audited) pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09)
**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

(b) Exhibits.

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

(c) Financial Statement Schedules.

Financial Statements for Stagecoach Gas Services LLC as of December 31, 2018 and 2018 and for the years ended December 31, 2018 and 2017 and for the period from June 3, 2016 to December 31, 2016 (audited) pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09) and is filed herein as Exhibit 99.1.

Crestwood Equity Partners LP
Crestwood Midstream Partners LP

Index to Financial Statements

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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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 22, 2019 expressed an unqualified opinion thereon.

Adoption of ASU No. 2014-09

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Update No. 2014-09, "Revenue from Contracts with Customers (Topic 606)."

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 22, 2019

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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, 2018, 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, 2018, 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, 2018 and 2017 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, 2018, and the related notes and financial statement schedules listed in the Index at Item 15(a) of the Company and our report dated February 22, 2019 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 22, 2019

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

	December 31,	
	2018	2017
Assets		
Current assets:		
Cash	$0.9	$1.3
Restricted cash	16.3	—
Accounts receivable, less allowance for doubtful accounts of $0.3 million and $2.4 million at December 31, 2018 and 2017	251.5	442.7
Inventory	64.6	68.4
Assets from price risk management activities	34.7	7.2
Prepaid expenses and other current assets	11.3	10.9
Total current assets	379.3	530.5
Property, plant and equipment	2,598.1	2,285.2
Less: accumulated depreciation and depletion	568.4	464.4
Property, plant and equipment, net	2,029.7	1,820.8
Intangible assets	770.3	788.8
Less: accumulated amortization	216.5	191.6
Intangible assets, net	553.8	597.2
Goodwill	138.6	147.6
Investments in unconsolidated affiliates	1,188.2	1,183.0
Other non-current assets	4.9	5.8
Total assets	$4,294.5	$4,284.9
Liabilities and partners' capital		
Current liabilities:		
Accounts payable	$213.0	$349.4
Accrued expenses and other liabilities	112.4	105.9
Liabilities from price risk management activities	5.8	48.9
Current portion of long-term debt	0.9	0.9
Total current liabilities	332.1	505.1
Long-term debt, less current portion	1,752.4	1,491.3
Other long-term liabilities	173.6	104.7
Deferred income taxes	2.6	3.3
Commitments and contingencies (Note 15)		
Partners' capital:		
Crestwood Equity Partners LP partners' capital (71,659,385 and 70,721,563 common and subordinated units issued and outstanding at December 31, 2018 and 2017)	1,240.5	1,393.5
Preferred units (71,257,445 units issued and outstanding at December 31, 2018 and 2017)	612.0	612.0
Total Crestwood Equity Partners LP partners' capital	1,852.5	2,005.5
Interest of non-controlling partner in subsidiary	181.3	175.0
Total partners' capital	2,033.8	2,180.5
Total liabilities and partners' capital	$4,294.5	$4,284.9

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,		
	2018	2017	2016
Revenues:			
Product revenues:			
Gathering and processing	$670.5	$1,369.1	$825.5
Marketing, supply and logistics	2,639.2	2,093.1	1,144.3
	3,309.7	3,462.2	1,969.8
Service revenues:			
Gathering and processing	276.1	317.3	290.7
Storage and transportation	17.1	37.2	165.3
Marketing, supply and logistics	50.2	62.4	92.1
Related party (Note 16)	1.0	1.8	2.6
	344.4	418.7	550.7
Total revenues	3,654.1	3,880.9	2,520.5
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	2,950.5	3,309.5	1,851.9
Product costs - related party (Note 16)	134.7	15.3	17.7
Service costs	44.2	49.9	55.5
Total costs of products/services sold	3,129.4	3,374.7	1,925.1
Operating expenses and other:			
Operations and maintenance	125.8	136.0	158.1
General and administrative	88.1	96.5	88.2
Depreciation, amortization and accretion	168.7	191.7	229.6
Loss on long-lived assets, net	28.6	65.6	65.6
Goodwill impairment	—	38.8	162.6
Loss on contingent consideration	—	57.0	—
	411.2	585.6	704.1
Operating income (loss)	113.5	(79.4)	(108.7)

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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,		
	2018	2017	2016
Earnings from unconsolidated affiliates, net	53.3	47.8	31.5
Interest and debt expense, net	(99.2)	(99.4)	(125.1)
Gain (loss) on modification/extinguishment of debt	(0.9)	(37.7)	10.0
Other income, net	0.4	1.3	0.5
Income (loss) before income taxes	67.1	(167.4)	(191.8)
(Provision) benefit for income taxes	(0.1)	0.8	(0.3)
Net income (loss)	67.0	(166.6)	(192.1)
Net income attributable to non-controlling partner	16.2	25.3	24.2
Net income (loss) attributable to Crestwood Equity Partners LP	50.8	(191.9)	(216.3)
Net income attributable to preferred units	60.1	62.5	28.7
Net loss attributable to partners	$(9.3)	$(254.4)	$(245.0)
Common unitholders’ interest in net loss	$(9.3)	$(254.4)	$(245.0)
Net loss per limited partner unit:			
Basic	$(0.13)	$(3.64)	$(3.55)
Diluted	$(0.13)	$(3.64)	$(3.55)
Weighted-average limited partners’ units outstanding (in thousands):			
Basic	71,205	69,839	69,017
Dilutive units	—	—	—
Diluted	71,205	69,839	69,017

See accompanying notes.

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

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$67.0	$(166.6)	$(192.1)
Change in fair value of Suburban Propane Partners, L.P. units	(0.7)	(0.8)	0.8
Comprehensive income (loss)	66.3	(167.4)	(191.3)
Comprehensive income attributable to non-controlling partner	16.2	25.3	24.2
Comprehensive income (loss) attributable to Crestwood Equity Partners LP	$50.1	$(192.7)	$(215.5)

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 Partner	Total Partners' Capital
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
Cumulative effect of accounting change (Note 2)	—	—	—	—	7.5	—	7.5
Distributions to partners	—	(60.1)	—	—	(170.8)	(9.9)	(240.8)
Unit-based compensation charges	—	—	1.1	—	28.5	—	28.5
Taxes paid for unit-based compensation vesting	—	—	(0.2)	—	(7.4)	—	(7.4)
Change in fair value of Suburban Propane Partners, L.P. units	—	—	—	—	(0.7)	—	(0.7)
Other	—	—	—	—	(0.8)	—	(0.8)
Net income (loss)	—	60.1	—	—	(9.3)	16.2	67.0
Balance at December 31, 2018	71.3	$612.0	71.2	0.4	$1,240.5	$ 181.3	$2,033.8

See accompanying notes.

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

	Year Ended December 31,		
	2018	2017	2016
Operating activities			
Net income (loss)	$67.0	$(166.6)	$(192.1)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	168.7	191.7	229.6
Amortization of deferred financing costs	6.8	7.2	6.9
Unit-based compensation charges	28.5	25.5	19.2
Loss on long-lived assets, net	28.6	65.6	65.6
Goodwill impairment	—	38.8	162.6
Loss on contingent consideration	—	57.0	—
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)
Earnings from unconsolidated affiliates, net, adjusted for cash distributions received	0.5	(0.1)	7.6
Deferred income taxes	(0.7)	(2.1)	(3.1)
Other	0.2	0.9	1.9
Changes in operating assets and liabilities:			
Accounts receivable	167.8	(170.7)	(76.9)
Inventory	(24.1)	(9.9)	(22.5)
Prepaid expenses and other current assets	(3.1)	1.8	9.2
Accounts payable, accrued expenses and other liabilities	(138.6)	140.1	74.6
Reimbursements of property, plant and equipment	21.7	19.6	26.0
Change in price risk management activities, net	(70.6)	19.4	47.5
Net cash provided by operating activities	253.6	255.9	346.1
Investing activities			
Acquisitions, net of cash acquired	—	—	(7.2)
Purchases of property, plant and equipment	(305.5)	(188.4)	(100.7)
Investment in unconsolidated affiliates	(64.4)	(58.0)	(12.4)
Capital distributions from unconsolidated affiliates	49.2	59.9	14.8
Net proceeds from sale of assets	79.5	225.2	972.7
Net cash provided by (used in) investing activities	(241.2)	38.7	867.2

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

	Year Ended December 31,		
	2018	2017	2016
Financing activities			
Proceeds from the issuance of long-term debt	2,274.8	2,838.6	1,565.3
Payments on long-term debt	(2,015.7)	(2,913.9)	(2,536.3)
Payments on capital leases	(1.6)	(2.7)	(1.9)
Payments for deferred financing costs	(5.7)	(1.0)	(3.5)
Redemption of non-controlling interest	—	(202.7)	—
Net proceeds from issuance of non-controlling interest	—	175.0	—
Distributions to partners	(170.8)	(167.6)	(219.8)
Distributions to non-controlling partner	(9.9)	(15.2)	(15.2)
Distributions to preferred unitholders	(60.1)	(15.0)	—
Net proceeds from issuance of common units	—	15.2	—
Taxes paid for unit-based compensation vesting	(7.4)	(5.5)	(0.8)
Other	(0.1)	(0.1)	—
Net cash provided by (used in) financing activities	3.5	(294.9)	(1,212.2)
Net change in cash and restricted cash	15.9	(0.3)	1.1
Cash and restricted cash at beginning of period	1.3	1.6	0.5
Cash and restricted cash at end of period	$17.2	$1.3	$1.6
Supplemental disclosure of cash flow information			
Cash paid during the period for interest	$97.4	$95.1	$121.5
Cash paid during the period for income taxes	$3.1	$3.1	$1.4
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$0.3	$(20.4)	$(10.5)

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, 2018 and 2017, and the related consolidated statements of operations, partners’ capital and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and financial statement schedule 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

Adoption of ASU No. 2014-09

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Update No. 2014-09, “Revenue from Contracts with Customers (Topic 606).”

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 22, 2019

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CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash	$0.2	$1.0
Restricted cash	16.3	—
Accounts receivable, less allowance for doubtful accounts of $0.3 million and $2.4 million at December 31, 2018 and 2017	249.9	442.6
Inventory	64.6	68.4
Assets from price risk management activities	34.7	7.2
Prepaid expenses and other current assets	11.3	10.9
Total current assets	377.0	530.1
Property, plant and equipment	2,928.2	2,615.3
Less: accumulated depreciation and depletion	725.9	607.8
Property, plant and equipment, net	2,202.3	2,007.5
Intangible assets	770.3	773.3
Less: accumulated amortization	216.5	177.6
Intangible assets, net	553.8	595.7
Goodwill	138.6	147.6
Investments in unconsolidated affiliates	1,188.2	1,183.0
Other non-current assets	2.1	2.4
Total assets	$4,462.0	$4,466.3
Liabilities and partners’ capital		
Current liabilities:		
Accounts payable	$210.5	$346.8
Accrued expenses and other liabilities	111.3	104.7
Liabilities from price risk management activities	5.8	48.9
Current portion of long-term debt	0.9	0.9
Total current liabilities	328.5	501.3
Long-term debt, less current portion	1,752.4	1,491.3
Other long-term liabilities	171.0	102.6
Deferred income taxes	0.6	0.7
Commitments and contingencies (Note 15)		
Partners’ capital	2,028.2	2,195.4
Interest of non-controlling partner in subsidiary	181.3	175.0
Total partners’ capital	2,209.5	2,370.4
Total liabilities and partners’ capital	$4,462.0	$4,466.3

See accompanying notes.

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

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Product revenues:			
Gathering and processing	$670.5	$1,369.1	$825.5
Marketing, supply and logistics	2,639.2	2,093.1	1,144.3
	3,309.7	3,462.2	1,969.8
Service revenues:			
Gathering and processing	276.1	317.3	290.7
Storage and transportation	17.1	37.2	165.3
Marketing, supply and logistics	50.2	62.4	92.1
Related party (Note 16)	1.0	1.8	2.6
	344.4	418.7	550.7
Total revenues	3,654.1	3,880.9	2,520.5
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	2,950.5	3,309.5	1,851.9
Product costs - related party (Note 16)	134.7	15.3	17.7
Service costs	44.2	49.9	55.5
Total costs of products/services sold	3,129.4	3,374.7	1,925.1
Operating expenses and other:			
Operations and maintenance	125.8	136.0	155.0
General and administrative	83.5	93.1	85.6
Depreciation, amortization and accretion	181.4	202.7	240.5
Loss on long-lived assets, net	28.6	65.6	65.6
Goodwill impairment	—	38.8	162.6
Loss on contingent consideration	—	57.0	—
	419.3	593.2	709.3
Operating income (loss)	105.4	(87.0)	(113.9)
Earnings from unconsolidated affiliates, net	53.3	47.8	31.5
Interest and debt expense, net	(99.2)	(99.4)	(125.1)
Gain (loss) on modification/extinguishment of debt	(0.9)	(37.7)	10.0
Other income, net	—	0.8	—
Net income (loss)	58.6	(175.5)	(197.5)
Net income attributable to non-controlling partner	16.2	25.3	24.2
Net income (loss) attributable to Crestwood Midstream Partners LP	$42.4	$(200.8)	$(221.7)

See accompanying notes.

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

	Partners	Non-controlling Partners	Total Partners' Capital
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
Cumulative effect of accounting change (Note 2)	7.5	—	7.5
Distributions to partners	(238.4)	(9.9)	(248.3)
Unit-based compensation charges	28.5	—	28.5
Taxes paid for unit-based compensation vesting	(7.4)	—	(7.4)
Other	0.2	—	0.2
Net income	42.4	16.2	58.6
Balance at December 31, 2018	$2,028.2	$ 181.3	$ 2,209.5

See accompanying notes.

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

	Year Ended December 31,		
	2018	2017	2016
Operating activities			
Net income (loss)	$58.6	$(175.5)	$(197.5)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	181.4	202.7	240.5
Amortization of deferred financing costs	6.8	7.2	6.9
Unit-based compensation charges	28.5	25.5	19.2
Loss on long-lived assets, net	28.6	65.6	65.6
Goodwill impairment	—	38.8	162.6
Loss on contingent consideration	—	57.0	—
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)
Earnings from unconsolidated affiliates, net, adjusted for cash distributions received	0.5	(0.1)	7.6
Deferred income taxes	(0.1)	—	0.2
Other	0.2	0.9	1.9
Changes in operating assets and liabilities:			
Accounts receivable	169.3	(170.5)	(76.9)
Inventory	(24.1)	(9.9)	(22.5)
Prepaid expenses and other current assets	(3.1)	1.8	7.5
Accounts payable, accrued expenses and other liabilities	(138.1)	142.0	75.2
Reimbursements of property, plant and equipment	21.7	19.6	26.0
Change in price risk management activities, net	(70.6)	19.4	47.5
Net cash provided by operating activities	260.5	262.2	353.8
Investing activities			
Acquisitions, net of cash acquired	—	—	(7.2)
Purchases of property, plant and equipment	(305.5)	(188.4)	(100.7)
Investment in unconsolidated affiliates	(64.4)	(58.0)	(12.4)
Capital distributions from unconsolidated affiliates	49.2	59.9	14.8
Net proceeds from sale of assets	79.5	225.2	972.7
Net cash provided by (used in) investing activities	(241.2)	38.7	867.2

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

	Year Ended December 31,		
	2018	2017	2016
Financing activities			
Proceeds from the issuance of long-term debt	2,274.8	2,838.6	1,565.3
Payments on long-term debt	(2,015.7)	(2,913.9)	(2,536.1)
Payments on capital leases	(1.6)	(2.7)	(1.9)
Payments for deferred financing costs	(5.7)	(1.0)	(3.5)
Redemption of non-controlling interest	—	(202.7)	—
Net proceeds from issuance of non-controlling interest	—	175.0	—
Distributions to partner	(238.4)	(174.0)	(227.6)
Distributions to non-controlling partner	(9.9)	(15.2)	(15.2)
Taxes paid for unit-based compensation vesting	(7.4)	(5.5)	(0.8)
Other	0.1	0.2	—
Net cash used in financing activities	(3.8)	(301.2)	(1,219.8)
Net change in cash and restricted cash	15.5	(0.3)	1.2
Cash and restricted cash at beginning of period	1.0	1.3	0.1
Cash and restricted cash at end of period	$16.5	$1.0	$1.3
Supplemental disclosure of cash flow information			
Cash paid during the period for interest	$97.4	$95.1	$121.5
Cash paid during the period for income taxes	$0.6	$0.6	$0.7
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$0.3	$(20.4)	$(10.5)

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.

The diagram below reflects a simplified version of our ownership structure as of December 31, 2018:

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, New Jersey, New York, North Carolina and Rhode Island, and our truck maintenance facilities located in Indiana, Mississippi, New Jersey and Ohio; (ii) our Bath and Seymour NGL storage facilities located in New York and Indiana; and (iii) 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.

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).

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In October 2016, Crestwood Infrastructure Holdings LLC (Crestwood Infrastructure), our wholly-owned subsidiary, and an affiliate of First Reserve formed the Crestwood Permian joint venture 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 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, 2018 and 2017. See Note 6 for a further discussion of our investment in Crestwood Permian.

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.

Restricted Cash

On January 1, 2018, we adopted the provisions of ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force) which changed the classification and presentation of restricted cash in the statement of cash flows. The standard requires us to include restricted cash in our total cash when reconciling the beginning of period and end of period amounts shown on our consolidated statements of cash flows. The retrospective application of this ASU did not have an impact on our consolidated statements of cash flows for the years ended December 31, 2017 and 2016.

Our restricted cash represents cash held under the terms of certain contractual agreements and is classified as current on our consolidated balance sheets. The change in restricted cash for the year ended December 31, 2018 is approximately $16.3 million and is included in operating activities (change in accounts payable, accrued expenses and other liabilities) in the consolidated statements of cash flows.

Inventory

Inventory for our marketing, supply and logistics operations are stated at the lower of cost or net realizable value and cost is computed predominantly using the average cost method. Our inventory consists primarily of crude oil and NGLs of approximately $64.2 million and $67.9 million at December 31, 2018 and 2017.

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

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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.

We did not record impairments of our property, plant and equipment during the year ended December 31, 2018 and 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. At December 31, 2017, our estimates of fair value considered a number of factors, including the potential value if we sold the asset, a 12% discount rate and projected cash flows, which is a Level 3 fair value measurement. During 2018, we sold our MS&L West Coast operations for $70.5 million, and recorded a loss on long-lived assets of approximately $26.9 million (including $9.0 million related to the write off of goodwill). See “Goodwill” below and Note 3 for further information on the sale of these assets.

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.

We did not record impairments of our intangible assets during the year ended December 31, 2018. During 2017 and 2016, 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. During 2018, we sold our MS&L West Coast operations for $70.5 million, and recorded a $26.9 million of loss on long-lived assets associated with the sale. See Note 3 for further information on the sale of these assets.

- 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.

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	10

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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.

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 and 2016. We did not record impairments of our goodwill during the year ended December 31, 2018. At December 31, 2018, our accumulated goodwill impairments at CEQP and CMLP were approximately $1,656.5 million and $1,399.3 million, respectively. The following table summarizes the goodwill of our various reporting units (in millions):

	Goodwill Impairments during the Year Ended December 31, 2016	Goodwill at January 1, 2017	Impact of Sale of US Salt	Goodwill Impairments during the Year Ended December 31, 2017	Goodwill at December 31, 2017	Other	Impact of Sale of West Coast	Goodwill at December 31, 2018
G&P								
Marcellus	$ 8.6	$ —	$—	$ —	$ —	$ —	$—	$ —
Arrow	—	45.9	—	—	45.9	—	—	45.9
S&T								
COLT	44.9	—	—	—	—	—	—	—
MS&L								
NGL Marketing and	—	—	—	—	—	101.7 (2)	(9.0) (1)	92.7

Logistics								
West Coast	—	2.4	—	2.4	—	—	—	—
Supply and Logistics	65.5	101.7	—	—	101.7	(101.7) [2]	—	—
Storage and Terminals	14.1	36.4	—	36.4	—	—	—	—
US Salt	—	12.6	(12.6) [1]	—	—	—	—	—
Trucking	29.5	—	—	—	—	—	—	—
Total	$ 162.6	$ 199.0	$ (12.6)	$ 38.8	$ 147.6	$ —	$ (9.0)	$ 138.6

(1) In December 2017, we sold 100% of our equity interests in US Salt to an affiliate of Kissner Group Holdings LP. In October 2018, we sold our West Coast assets and wrote off the goodwill attributable to these assets as further discussed below.

(2) Reflects the combination of the MS&L reporting units into one NGL Marketing and Logistics reporting unit as further discussed below.

On January 1, 2018, we combined the four reporting units included in the MS&L segment into one NGL Marketing and Logistics reporting unit for the purpose of evaluating goodwill for impairment on an ongoing basis. We combined these reporting units based on a strategic shift in the way in which we manage, operate and report our NGL operations as an integrated platform instead of as four individual stand-alone operations. We allocated approximately $9.0 million of the goodwill associated with our NGL Marketing and Logistics reporting unit to the West Coast facilities during 2018, and this goodwill was included in the loss on the sale of the West Coast assets. See Note 3 for a further discussion of the sale of our West Coast assets.

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. 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.

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.

Investments 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. We did not record impairments of our equity method investments during the years ended December 31, 2018, 2017 and 2016.

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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.

We have various obligations to remove property, plant and equipment on rights-of-way and leases for which we cannot currently estimate the fair value of those obligations because the associated assets have indeterminate lives. An asset retirement obligation liability (and related assets), if any, will be recorded for these obligations once sufficient information is available to reasonably estimate the fair value of the obligations. At December 31, 2018 and 2017, 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. Our net deferred financing costs are reflected as a reduction of long-term debt on our consolidated balance sheets.

Revenue Recognition

We provide gathering, processing, compression, storage, fractionation, and transportation (consisting of pipelines, truck and rail terminals, truck/trailer units and rail cars) services and we sell commodities (including crude oil, natural gas, NGLs and water) under various contracts. These contracts include:

- Fixed-fee contracts. Under these contracts, we do not take title to the underlying crude oil, natural gas or NGLs but charge our customers a fixed-fee for the services we provide, which can be a firm reservation charge and/or a charge per volume gathered, processed, compressed, stored, loaded and/or transported (which, in certain contracts, can be subject to a minimum level of volumes);
- Percentage-of-proceeds service contracts. Under these contracts, we take title to crude oil, 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 take title to crude oil, natural gas or NGLs before the commodity enters our 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 oil, natural gas or NGLs before the commodity enters our facilities, and we market and sell those commodities to third parties.

On January 1, 2018, we adopted the provisions of ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. We adopted the standard using the modified retrospective method for all revenue contracts that involve revenue generating activities that occur after January 1, 2018. Results for reporting periods beginning after January 1, 2018 are presented under the new standard, while amounts prior to January 1, 2018 continue to be reported in accordance with our historic accounting under Revenue Recognition (Topic 605).

Prior to January 1, 2018, we recognized revenues for services and products when all of the following criteria were met under Topic 605: (i) services had been rendered or products delivered or sold; (ii) persuasive evidence of an exchange arrangement existed; (iii) the price for services was fixed or determinable; and (iv) collectability was reasonably assured. We recorded deferred revenue when we received amounts from our customers but had not yet met the criteria listed above. We recognized deferred revenue in our consolidated statement of operations when the criteria had been met and all services had been rendered. At December 31, 2017, we had deferred revenue of approximately $0.6 million, which is reflected in accrued expenses and other liabilities on our consolidated balance sheet.

Beginning January 1, 2018, we recognize revenues for services and products under revenue contracts as our obligations to perform services or deliver/sell products under the contracts are satisfied. A contract’s transaction price is allocated to each

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performance obligation in the contract and recognized as revenue when, or as, the performance obligation is satisfied. Our fixed-fee contracts and our percentage-of-proceeds service contracts primarily have a single performance obligation to deliver a series of distinct goods or services that are substantially the same and have the same pattern of transfer to our customers. For performance obligations associated with these contracts, we recognize revenues over time utilizing the output method based on the actual volumes of products delivered/sold or services performed, because the single performance obligation is satisfied over time using the same performance measure of progress toward satisfaction of the performance obligation. The transaction price under certain of our fixed-price contracts and percentage-of-proceeds service contracts includes variable consideration that varies primarily based on actual volumes that are delivered under the contracts. Because the variable consideration specifically relates to our efforts to transfer the services and/or products under the contracts, we allocate the variable consideration entirely to the distinct service utilizing the allocation exception guidance under Topic 606, and accordingly recognize the variable consideration as revenues at the time the good or service is transferred to the customer.

Certain of our fixed-fee contracts contain minimum volume features under which the customers must utilize our services to gather, compress or load a specified quantity of crude oil or natural gas or pay a deficiency fee based on the difference between actual volumes and the contractual minimum volume. We recognize revenues from these contracts when actual volumes are gathered, compressed or loaded and the likelihood of a customer exercising its remaining rights to make up the deficient volumes under minimum volume commitments becomes remote.

We recognize revenues at a point in time for performance obligations associated with our percentage-of proceeds product contracts and purchase and sale contracts, and these revenues are recognized because control of the underlying product is transferred to the customer when the distinct good is provided to the customer.

The evaluation of when performance obligations have been satisfied and the transaction price that is allocated to our performance obligations requires significant judgments and assumptions, including our evaluation of the timing of when control of the underlying good or service has transferred to our customers and the relative standalone selling price of goods and services provided to customers under contracts with multiple performance obligations. Actual results can significantly vary from those judgments and assumptions. We did not have any material contracts with multiple performance obligations or under which we receive material amounts of non-cash consideration during the year ended December 31, 2018.

The following table summarizes the transaction price allocated to our remaining performance obligations under certain contracts that have not been recognized as of December 31, 2018 (in millions):

2019	$32.5
2020	23.5
2021	9.4
2022	7.3
2023	7.3
Thereafter	3.3
Total	$83.3

Our remaining performance obligations presented in the table above exclude estimates of variable rate escalation clauses in our contracts with customers, and is generally limited to fixed-fee and percentage-of-proceeds service contracts which have fixed pricing and minimum volume terms and conditions. Our remaining performance obligations generally exclude, based on the following practical expedients that we elected to apply, disclosures for (i) variable consideration allocated to a wholly-unsatisfied promise to transfer a distinct service that forms part of the identified single performance obligation; (ii) unsatisfied performance obligations where the contract term is one year or less; and (iii) contracts for which we recognize revenues as amounts are invoiced.

Contract Assets and Contract Liabilities. Amounts due from our customers under our revenue contracts are typically billed as the service is being provided or on a weekly, bi-weekly or monthly basis and are due within 30 days of billing. Under certain of our contracts, we recognize revenues in excess of billings which we present as contract assets on our consolidated balance sheets.

Under certain contracts, we may be entitled to receive payments in advance of satisfying our performance obligations under the contract. We recognize a liability for these payments in excess of revenue recognized and present it as deferred revenue or contract liabilities on our consolidated balance sheets. Our deferred revenue primarily relates to:

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- Capital Reimbursements. Certain contracts in our G&P segment require that our customers reimburse us for capital expenditures related to the construction of long-lived assets utilized to provide services to them under the revenue contracts. Because we consider these amounts as consideration from customers associated with ongoing services to be provided to customers, we defer these upfront payments in deferred revenue and recognize the amounts in revenue over the life of the associated revenue contract as the performance obligations are satisfied under the contract. On January 1, 2018, we recorded an $87.6 million increase to our property, plant and equipment, net, a $69.1 million increase to our deferred revenue liability and an $18.5 million increase to partners' capital as a result of applying the cumulative impact of adopting the new standard on these types of contracts.

- Contracts with Increasing (Decreasing) Rates per Unit. Certain contracts in our G&P, S&T and MS&L segments have fixed rates per volume that increase and/or decrease over the life of the contract once certain time periods or thresholds are met. We record revenues on these contracts ratably per unit over the life of the contract based on the remaining performance obligations to be performed, which can result in the deferral of revenue for the difference between the consideration received and the ratable revenue recognized. On January 1, 2018, we recorded a $1.5 million increase to our deferred revenue liability and a corresponding decrease to partners' capital as a result of applying the cumulative impact of adopting the new standard on these types of contracts.

Our contract assets and contract liabilities are reported in a net position on a contract-by-contract basis at the end of each reporting period. Our receivables related to our Topic 606 revenue contracts totaled $209.7 million for both CEQP and CMLP at December 31, 2018, and are included in accounts receivable on our consolidated balance sheet. Our contract assets are included in other non-current assets on our consolidated balance sheet. Our contract liabilities primarily consist of current and non-current deferred revenues. On our consolidated balance sheets, our current deferred revenues are included in accrued expenses and other liabilities and our non-current deferred revenues are included in other long-term liabilities. The majority of revenues associated with our deferred revenues is expected to be recognized as the performance obligations under the related revenue contracts are satisfied over the next 13 years.

The following table summarizes the opening and closing balances of our contract assets and contract liabilities (in millions):

	Balance at January 1, 2018	Balance at December 31, 2018
Contract Assets (Non-current)	$ 1.1	$ 1.0
Contract Liabilities (Current)[(1)]	12.2	12.0
Contract Liabilities (Non-current)[(1)]	60.6	65.4

(1) During the year ended December 31, 2018, we recognized revenues of approximately $12.2 million that were previously included in contract liabilities (current) at January 1, 2018. The remaining change in our contract liabilities during the year ended December 31, 2018, primarily related to capital reimbursements associated with our revenue contracts and revenue deferrals associated with our contracts with increasing (decreasing) rates.

Impact of financial statement line items. For contracts that were modified prior to January 1, 2018, we have not retrospectively restated the contract for those modifications and instead we have reflected the aggregate effect of those modifications when identifying satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to satisfied and unsatisfied obligations. The impact of applying this transition practical expedient was not material to our financial statements. The adoption of Topic 606 had the following impact on CEQP's and CMLP's consolidated income statements and balance sheets (in millions):

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Crestwood Equity

	Year Ended December 31, 2018		
	As Reported under Topic 606	Prior to Adoption of Topic 606	Increase (Decrease)
Income Statement			
Product revenues:			
Gathering and processing(1)	$670.5	$1,643.1	$(972.6)
Service revenues:			
Gathering and processing(1)(2)	276.1	318.9	(42.8)
Marketing, supply and logistics(3)	50.2	49.4	0.8
Costs of product/services sold:			
Product costs(1)	2,950.5	3,977.3	(1,026.8)
Depreciation, amortization and accretion(2)	168.7	163.7	5.0
Earnings from unconsolidated affiliates, net(4)	53.3	63.0	(9.7)
Net income	67.0	69.5	(2.5)

	December 31, 2018		
	As Reported under Topic 606	Prior to Adoption of Topic 606	Increase (Decrease)
Balance Sheet			
Assets:			
Property, plant and equipment(2)	$2,598.1	$2,480.1	$118.0
Accumulated depreciation and depletion(2)	568.4	551.2	17.2
Investments in unconsolidated affiliates(4)	1,188.2	1,207.4	(19.2)
Liabilities:			
Accrued expenses and other liabilities(2)(3)	112.4	101.2	11.2
Other long-term liabilities(2)(3)	173.6	108.2	65.4
Partners' capital:			
Crestwood Equity Partners LP partners' capital(2)(3)(4)	1,240.5	1,235.5	5.0

Crestwood Midstream

	Year Ended December 31, 2018		
	As Reported under Topic 606	Prior to Adoption of Topic 606	Increase (Decrease)
Income Statement			
Product revenues:			
Gathering and processing(1)	$670.5	$1,643.1	$(972.6)
Service revenues:			

Gathering and processing[1][2]	276.1	318.9	(42.8	)
Marketing, supply and logistics[3]	50.2	49.4	0.8	
Costs of product/services sold:				
Product costs[1]	2,950.5	3,977.3	(1,026.8	)
Depreciation, amortization and accretion[2]	181.4	176.4	5.0	
Earnings from unconsolidated affiliates, net[4]	53.3	63.0	(9.7	)
Net income	58.6	61.1	(2.5	)

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	December 31, 2018		
	As Reported under Topic 606	Prior to Adoption of Topic 606	Increase (Decrease)
Balance Sheet			
Assets:			
Property, plant and equipment[(2)]	$2,928.2	$2,810.2	$ 118.0
Accumulated depreciation and depletion[(2)]	725.9	708.7	17.2
Investments in unconsolidated affiliates[(4)]	1,188.2	1,207.4	(19.2)
Liabilities:			
Accrued expenses and other liabilities[(2)(3)]	111.3	100.1	11.2
Other long-term liabilities[(2)(3)]	171.0	105.6	65.4
Partners' capital[(2)(3)(4)]	2,028.2	2,023.2	5.0

(1) On January 1, 2018, we began classifying product and service revenues as a reduction of costs of product sold on certain of our gathering and processing contracts.

(2) On January 1, 2018, we began recording proceeds received from customers for reimbursable construction as deferred revenue instead of as reductions of property, plant and equipment.

(3) For contracts that have fixed rates per volume that increase and/or decrease over the life of the contract once certain time periods or thresholds have been met, on January 1, 2018, we began recording revenues on those contracts ratably per unit over the life of the contract based on the remaining performance obligations to be performed.

(4) On January 1, 2018, Jackalope Gas Gathering Services, L.L.C. (Jackalope) adopted the provisions of Topic 606, and we recorded a $9.5 million decrease to our equity method investment and a corresponding decrease to our partners' capital to reflect our proportionate share of the cumulative effect of accounting change recorded by the equity investment related to the new standard. In addition, our earnings from unconsolidated affiliates decreased by approximately $9.7 million during the year ended December 31, 2018 to reflect our proportionate share of the ongoing impact of the new standard on Jackalope's revenues. The adoption of Topic 606 was not material to our other equity method investments.

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.

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.

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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, 2018, 2017 or 2016.

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.

Cash Flows

Effective January 1, 2018, we adopted the provisions of 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. The adoption of this standard did not have a material impact on our consolidated financial statements.

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New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2018, the following accounting standard had not yet been adopted by us:

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 will utilize the modified retrospective method to adopt the provisions of this standard effective January 1, 2019. As allowed for in the standard, upon adoption we will not reassess the current GAAP classification of leases, easements and rights of way that existed as of December 31, 2018, and we will not utilize the hindsight method in determining the assets and liabilities to be recorded for our existing leases on January 1, 2019. Upon adoption of this standard, we anticipate increasing non-current assets by approximately $69 million, increasing current liabilities by approximately $19 million and increasing non-current liabilities by approximately $50 million, related to reflecting our operating and capital leases on our consolidated balance sheets under the provisions of the new standard. We do not anticipate recording a material cumulative effect of accounting change related to the adoption of the standard.

Note 3 – Divestitures

In October 2018, we sold our West Coast assets to a third party for proceeds of approximately $70.5 million. The West Coast assets included a gas gathering and processing system, fractionator, butamer and various rail and truck terminal and storage facilities located in California, Nevada, Wyoming and Utah. The sale of West Coast resulted in a decrease of $61.8 million of property, plant and equipment, net, $9.0 million of goodwill and $26.6 million of other assets and liabilities, net. During the year ended December 31, 2018, we recognized a loss from the sale of approximately $26.9 million (including the goodwill write off discussed in Note 2), which was included in loss on long-lived assets in our consolidated statement of operations. Our West Coast assets were previously included in our MS&L segment.

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 from the sale of approximately $33.6 million (including the goodwill write off discussed in Note 2, which was included in gain (loss) on long-lived assets in our consolidated statement of operations. US Salt was previously included in our MS&L segment.

Note 4 – Certain Balance Sheet Information

Property, Plant and Equipment

Property, plant and equipment consisted of the following at December 31, 2018 and 2017 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2018	2017	2018	2017
Gathering systems and pipelines and related assets	$758.6	$678.0	$901.5	$820.9
Facilities and equipment	1,230.7	1,141.4	1,415.9	1,326.5
Buildings, land, rights-of-way, storage rights and easements	331.7	319.1	335.4	322.8

Vehicles	17.9	37.3	16.1	35.5
Construction in process	230.8	87.5	230.8	87.5
Office furniture and fixtures	28.4	21.9	28.5	22.1
	2,598.1	2,285.2	2,928.2	2,615.3
Less: accumulated depreciation and depletion	568.4	464.4	725.9	607.8
Total property, plant and equipment, net	$2,029.7	$1,820.8	$2,202.3	$2,007.5

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Depreciation. CEQP's depreciation expense totaled $123.6 million, $135.9 million and $154.8 million for the years ended December 31, 2018, 2017 and 2016. CMLP's depreciation expense totaled $137.7 million, $150.0 million and $168.9 million for the years ended December 31, 2018, 2017 and 2016. Depletion expense at both CEQP and CMLP totaled $0.7 million for the years ended December 31, 2017 and 2016. We had no depletion expense for the year ended December 31, 2018.

Capitalized Interest. During the years ended December 31, 2018, 2017 and 2016, CEQP and CMLP capitalized interest of $5.0 million, $2.9 million and $0.7 million related to certain expansion projects.

Capital Leases. We had capital lease assets of $9.7 million and $2.1 million included in property, plant and equipment, net at December 31, 2018 and 2017, primarily related to certain vehicle leases.

Intangible Assets

Intangible assets consisted of the following at December 31, 2018 and 2017 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2018	2017	2018	2017
Customer accounts	$438.9	$438.9	$438.9	$438.9
Gas gathering, compression and processing contracts	325.2	325.2	325.2	325.2
Trademarks(1)	6.2	24.7	6.2	9.2
	770.3	788.8	770.3	773.3
Less: accumulated amortization	216.5	191.6	216.5	177.6
Total intangible assets, net	$553.8	$597.2	$553.8	$595.7

(1) As of December 31, 2018, we fully amortized and eliminated certain intangibles associated with our trademarks.

The following table summarizes total accumulated amortization of our intangible assets at December 31, 2018 and 2017 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2018	2017	2018	2017
Customer accounts	$112.1	$89.8	$112.1	$89.8
Gas gathering, compression and processing contracts	100.8	82.0	100.8	82.0
Trademarks	3.6	19.8	3.6	5.8
Total accumulated amortization	$216.5	$191.6	$216.5	$177.6

Crestwood Equity's amortization expense related to its intangible assets for the years ended December 31, 2018, 2017 and 2016, was approximately $43.5 million, $53.7 million and $72.5 million. Crestwood Midstream's amortization expense related to its intangible assets for the years ended December 31, 2018, 2017 and 2016 was approximately $42.1 million, $50.6 million and $69.3 million.

Estimated amortization of CEQP's and CMLP's intangible assets for the next five years is as follows (in millions):

Year Ending December 31,	
2019	$41.7
2020	41.7
2021	41.7
2022	41.7
2023	37.7

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Accrued Expenses and Other Liabilities

Accrued expenses and other liabilities consisted of the following at December 31, 2018 and 2017 (in millions):

	CEQP		CMLP	
	December 31,		December 31,	
	2018	2017	2018	2017
Accrued expenses[(1)]	$64.8	$56.6	$63.7	$55.5
Accrued property taxes	2.6	4.8	2.6	4.8
Income tax payable	0.3	0.3	0.3	0.3
Interest payable	19.8	20.3	19.8	20.3
Accrued additions to property, plant and equipment	10.5	22.3	10.5	22.2
Capital leases	2.4	1.0	2.4	1.0
Deferred revenue	12.0	0.6	12.0	0.6
Total accrued expenses and other liabilities	$112.4	$105.9	$111.3	$104.7

(1) Includes $16.2 million of related party accrued expenses at December 31, 2018 related to deposits received from Jackalope, our 50% equity method investment.

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.
The following table presents the changes in the net asset retirement obligations for the years ended December 31, 2018 and 2017 (in millions):

	December 31,	
	2018	2017
Net asset retirement obligation at January 1	$27.5	$27.8
Liabilities incurred	0.7	—
Liabilities settled	(2.2)	(1.2)
Accretion expense	1.6	1.4
Change in estimate	—	(0.5)
Net asset retirement obligation at December 31	$27.6	$27.5

We did not have any material assets that were legally restricted for use in settling asset retirement obligations as of December 31, 2018 and 2017.

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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,		
	2018	2018	2017	2018	2017	2016
Stagecoach Gas Services LLC	50.00 %	$830.4	$849.8	$29.3	$25.3	$15.9
Jackalope Gas Gathering Services, L.L.C.(1)	50.00 % (1)	210.2	184.9	18.1	10.5	20.8
Crestwood Permian Basin Holdings LLC(2)	50.00 %	104.3	102.0	4.4	8.4	(0.5)
Tres Palacios Holdings LLC	50.01 %	35.0	37.8	—	2.2	(0.3)
Powder River Basin Industrial Complex, LLC(3)	50.01 %	8.3	8.5	1.5	1.4	(4.4)
Total		$1,188.2	$1,183.0	$53.3	$47.8	$31.5

(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) Pursuant to the Crestwood Permian limited liability company agreement, we were allocated 100% of Crestwood New Mexico's earnings through June 30, 2018. Effective July 1, 2018, our equity earnings from Crestwood New Mexico is based on our ownership percentage of Crestwood Permian, which is currently 50%.

(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. For a further discussion of these impairments, see Note 2.

Description of Investments

Stagecoach Gas Services LLC

On June 3, 2016, Crestwood Northeast and CEGP formed Stagecoach Gas Services LLC (Stagecoach Gas) to own and further develop our NE S&T assets. During 2016, we contributed to Stagecoach Gas the entities owning the natural gas storage and transportation business located in the Northeast (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 and restricted 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. Our Stagecoach Gas investment is included in our storage and transportation segment.

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. As a result, our consolidated balance sheets reflect an other long-term liability of $57 million at December 31, 2018 and 2017, and our consolidated income statement for the year ended December 31, 2017 reflects a $57 million loss on contingent consideration related to this obligation.

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. Our Jackalope investment is included in our gathering and processing segment.

On January 1, 2018, Jackalope adopted the provisions of Topic 606, and we recorded a $9.5 million decrease to our equity method investment and a corresponding decrease to our partners' capital to reflect our proportionate share of the cumulative effect of accounting change recorded by Jackalope related to the new standard. In addition, our earnings from unconsolidated

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affiliates decreased by approximately $9.7 million during the year ended December 31, 2018 to reflect our proportionate share of Jackalope's deferred revenues related to the new standard.

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. Our Crestwood Permian investment is included in our gathering and processing segment.

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 Delaware Permian. SWEPI has dedicated to Crestwood Permian Basin the 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 estimated to cost approximately $180 million, of which approximately $145.6 million has been spent through December 31, 2018) 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, 2018 and 2017.

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 the accounting standards related to such transactions required Crestwood Permian to record the assets and liabilities of Crestwood New Mexico at our historical book value. 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 contributed to Crestwood Permian the first $151 million of capital costs required to fund the expansion of the Delaware Basin assets, which included a new processing plant located in Orla, Texas and associated pipelines that went into service in July 2018.

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. Our Tres Holdings investment is included in our storage and transportation segment.

Powder River Basin Industrial Complex, LLC

Crestwood Crude Logistics LLC, 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. Our PRBIC investment is included in our storage and transportation segment

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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, 2018					2017				
	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)]	$50.1	$ 1,725.1	$ 4.2	$ 0.9	$1,770.1	$55.1	$ 1,765.4	$ 7.0	$ 1.4	$1,812.1
Crestwood Permian[(2)]	17.7	372.6	16.8	94.7	278.8	37.6	203.3	33.4	1.8	205.7
Other[(3)]	59.3	658.0	17.4	129.6	570.3	43.7	597.8	20.0	91.8	529.7
Total	$127.1	$ 2,755.7	$ 38.4	$ 225.2	$2,619.2	$136.4	$ 2,566.5	$ 60.4	$ 95.0	$2,547.5

(1) As of December 31, 2018, our equity in the underlying net assets of Stagecoach Gas exceeded our investment balance by approximately $51.3 million. This excess amount is entirely attributable to goodwill and, as such, is not subject to amortization.

(2) As of December 31, 2018, the difference of approximately $8.9 million between our equity in Crestwood Permian's net assets and our investment balance is not subject to amortization.

(3) Includes our Jackalope, Tres Holdings and PRBIC equity investments. As of December 31, 2018, our equity in the underlying net assets of Jackalope, Tres Holdings and PRBIC exceeded our investment balance by approximately $0.4 million, $25.3 million and $5.9 million, respectively.

Operating Results Data

	Year Ended December 31, 2018			2017			2016		
	Operating Revenues	Operating Expenses	Net Income	Operating Revenues	Operating Expenses	Net Income	Operating Revenues	Operating Expenses	Net Income
Stagecoach	$171.4	$ 79.3	$92.1	$168.6	$ 77.7	$91.1	$99.3	$ 44.1	$ 55.3
Crestwood Permian	82.2	81.3	5.7	87.3	74.1	14.1	11.5	10.9	0.6
Other[(1)]	116.9	81.5	35.6	94.5	69.5	24.8	116.1	103.0	12.9
Total	$370.5	$ 242.1	$133.4	$350.4	$ 221.3	$130.0	$226.9	$ 158.0	$ 68.8

(1) Includes our Jackalope, Tres Holdings and PRBIC 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 each of the years ended December 31, 2018, 2017 and 2016, 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, 2018, 2017 and 2016, 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 $0.5 million, $0.6 million and $1.6 million for the years ended December 31, 2018, 2017 and 2016, which we amortize over the life of PRBIC's property, plant and equipment.

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Distributions and Contributions

	Distributions Year Ended December 31,			Contributions Year Ended December 31,		
	2018	2017	2016	2018	2017	2016
Stagecoach Gas	$48.7	$47.3	$16.0	$—	$0.8	$—
Jackalope[(1)]	32.4	26.3	27.4	49.1	3.5	1.4
Crestwood Permian[(2)]	14.7	23.4	—	12.6	117.5	—
Tres Holdings[(3)]	5.3	9.0	8.5	2.5	5.6	11.0
PRBIC[(1)]	1.9	1.6	2.0	0.2	—	—
Total	$103.0	$107.6	$53.9	$64.4	$127.4	$12.4

(1) Jackalope and PRBIC are required to make quarterly distributions of its available cash to its members based on their respective ownership percentage. In February 2019, we received a cash distribution of $11.6 million from Jackalope.
(2) 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.
(3) 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.

Stagecoach Gas. Stagecoach Gas is required, within 30 days following the end of each quarter, to distribute 60% and 40% of its available cash (as defined in its limited liability company agreement) to CEGP and us, respectively. Pursuant to the Stagecoach limited liability company agreement, our share of Stagecoach’s equity earnings increased from 35% to 40% effective July 1, 2018. Prior to July 1, 2018, Stagecoach Gas distributed 35% of its available cash to us. 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 2019, we received a cash distribution from Stagecoach Gas of approximately $13.0 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 received 100% of Crestwood New Mexico's available cash (as defined in the limited liability company agreement) through June 30, 2018, and subsequent to June 30, 2018, our distributions are 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 2019, we received a cash distribution from Crestwood Permian of approximately $2.3 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. Our commodity-based derivatives that are settled with physical commodities are reflected as an increase to product revenues, and the commodity inventory that is utilized to satisfy those physical obligations is reflected as an increase to costs of product sold in our consolidated statements of operations. The following table summarizes the impact to our consolidated statements of operations related to our commodity-based derivatives reflected in costs of products/services sold and operating revenues during the years ended December 31, 2018, 2017 and 2016 (in millions):

	December 31,		
	2018	2017	2016
Gain (loss) reflected in costs of product/services sold	$29.6	$(31.2)	$(7.8)
Product revenues	343.3	234.1	162.9

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, 2018		December 31, 2017	
	Fixed Price Payor	Fixed Price Receiver	Fixed Price Payor	Fixed Price Receiver
Propane, crude and heating oil (MMBbls)	27.8	30.1	15.3	17.5
Natural gas (MMcf)	1,800	1,800	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 36 months or less; however, 82% 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. In addition, we have margin requirements with a New York Mercantile Exchange (NYMEX) broker related to our net asset or liability position with such broker. 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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The following table represents the fair value of our commodity derivative instruments with credit-risk-related contingent features and their associated collateral (in millions):

	December 31, 2018	2017
Aggregate fair value of derivative instruments with credit-risk-related contingent features(1)	$2.2	$28.9
NYMEX-related net derivative asset (liability) position	(9.4)	27.2
NYMEX-related cash collateral posted	21.7	5.6
Cash collateral received	14.2	3.7

(1) At December 31, 2018 and 2017. we posted less than less than $0.1 million of collateral associated with these derivatives.

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, 2018 and 2017, the carrying amounts of cash, accounts receivable and accounts payable approximate the 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, 2018 and 2017, due primarily to the variable nature of the interest rate of the instrument, which is considered a Level 2 fair value measurement.

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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 amount (reduced for deferred financing costs associated with the respective notes) and fair value of our senior notes (in millions):

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
2023 Senior Notes	$693.6	$668.1	$692.1	$728.8
2025 Senior Notes	$493.4	$466.2	$492.3	$517.9

Financial Assets and Liabilities

As of December 31, 2018 and 2017, 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.

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.

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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, 2018 and 2017 (in millions):

	December 31, 2018						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/Margin Received or Paid	Fair Value
Assets							
Assets from price risk management	$12.4	$160.7	$—	$173.1	$(140.3)	$1.9	$34.7
Suburban Propane Partners, L.P. units[2]	2.8	—	—	2.8	—	—	2.8
Total assets at fair value	$15.2	$160.7	$—	$175.9	$(140.3)	$1.9	$37.5
Liabilities							
Liabilities from price risk management	$7.0	$144.7	$—	$151.7	$(140.3)	$(5.6)	$5.8
Total liabilities at fair value	$7.0	$144.7	$—	$151.7	$(140.3)	$(5.6)	$5.8

	December 31, 2017						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/Margin Received or Paid	Fair Value
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

(1) Amounts represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral held or placed with the same counterparties.
(2) Amount is reflected in other assets on CEQP's consolidated balance sheets.

Note 9 – Long-Term Debt

Long-term debt consisted of the following at December 31, 2018 and 2017, (in millions):

	December 31,	
	2018	2017
Credit Facility	$578.2	$318.2
2023 Senior Notes	700.0	700.0
2025 Senior Notes	500.0	500.0
Other	1.5	2.4
Less: deferred financing costs, net	26.4	28.4
Total debt	1,753.3	1,492.2
Less: current portion	0.9	0.9
Total long-term debt, less current portion	$1,752.4	$1,491.3

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Credit Facility

In October 2018, Crestwood Midstream entered into a Second Amended and Restated Agreement (the CMLP Credit Agreement). The CMLP Credit Agreement provides for a five-year $1.25 billion revolving credit facility (the CMLP Credit Facility), which expires in October 2023 and is available to fund acquisitions, working capital and internal growth projects and for general partnership purposes. The CMLP Credit Facility allows Crestwood Midstream to increase its available borrowings under the facility by $350.0 million, subject to lender approval and the satisfaction of certain other conditions, as described in the CMLP Credit Agreement. The CMLP Credit Facility also includes a sub-limit of up to $25.0 million for same-day swing line advances and a sub-limit up to $350.0 million for letters of credit. Subject to limited exception, the CMLP Credit Facility is guaranteed and secured by substantially all of the equity interests and assets of Crestwood Midstream's subsidiaries, except for Crestwood Niobrara, Crestwood Infrastructure, PRBIC, Crestwood Northeast and Tres Holdings and their respective subsidiaries. The Company also guarantees Crestwood Midstream's payment obligations under its $1.25 billion credit agreement.

Prior to amending and restating its credit agreement in October 2018, Crestwood Midstream had a five-year $1.5 billion senior secured revolving credit facility, which would have expired September 2020 (2020 Credit Facility). We recognized a loss on modification of debt of approximately $0.9 million for the year ended December 31, 2018 in conjunction with amending and restating the CMLP Credit Agreement.

Borrowings under the CMLP Credit Facility (other than the swing line loans) bear interest at either:

- the Alternate Base Rate, which is defined as the highest of (i) the federal funds rate plus 0.50%; (ii) Wells Fargo Bank's prime rate; or (iii) the Eurodollar Rate adjusted for certain reserve requirements plus 1%; plus a margin varying from 0.50% to 1.50% at December 31, 2018 depending on Crestwood Midstream's most recent consolidated total leverage ratio; or

- the Eurodollar Rate, adjusted for certain reserve requirements plus a margin varying from 1.50% to 2.50% at December 31, 2018 depending on Crestwood Midstream's most recent consolidated total leverage ratio.

Swing line loans bear interest at the Alternate Base Rate as described above. The unused portion of the CMLP Credit Facility is subject to a commitment fee ranging from 0.25% to 0.45% according to its most recent consolidated total leverage ratio. Interest on the Alternate Base Rate loans is payable quarterly, or if the adjusted Eurodollar Rate applies, interest is payable at certain intervals selected by Crestwood Midstream.

At December 31, 2018, Crestwood Midstream had $524.0 million of available capacity under its credit facility considering the most restrictive covenants in its credit agreement. At December 31, 2018 and 2017, Crestwood Midstream's outstanding standby letters of credit were $68.0 million and $52.2 million. Interest rates under the CMLP Credit Facility were between 4.63% and 6.75% at December 31, 2018 and the weighted-average interest on outstanding borrowings was 4.79%. Interest rates under the 2020 Credit Facility were between 3.94% and 6.00% at December 31, 2017 and the weighted-average interest rate on outstanding borrowings was 4.11%.

The CMLP Credit Facility contains various covenants and restrictive provisions that limit our ability to, among other things, (i) incur additional debt; (ii) make distributions on or redeem or repurchase units; (iii) make certain investments and acquisitions; (iv) incur or permit certain liens to exist; (v) merge, consolidate or amalgamate with another company; (vi) transfer or dispose of assets; and (vii) incur a change in control at either Crestwood Equity or Crestwood Midstream, including an acquisition of Crestwood Holdings' ownership of Crestwood Equity's general partner by any third party, including Crestwood Holdings' debtors under an event of default of their debt since Crestwood Equity's non-economic general partner interest is pledged as collateral under that debt.

Crestwood Midstream is required under its credit agreement to maintain a net debt to consolidated EBITDA ratio (as defined in its credit agreement) of not more than 5.50 to 1.0, a consolidated EBITDA to consolidated interest expense ratio (as defined in its credit agreement) of not less than 2.50 to 1.0, and a senior secured leverage ratio (as defined in its credit agreement) of not more than 3.75 to 1.0. At December 31, 2018, the net debt to consolidated EBITDA was approximately 4.25 to 1.0, the consolidated EBITDA to consolidated interest expense was approximately 4.40 to 1.0, and the senior secured leverage ratio was 1.38 to 1.0.

If Crestwood Midstream fails to perform its obligations under these and other covenants, the lenders' credit commitment could be terminated and any outstanding borrowings, together with accrued interest, under the CMLP Credit Facility could be declared immediately due and payable. The CMLP Credit Facility also has cross default provisions that apply to any of its other material indebtedness.

Senior Notes

2023 Senior Notes. The 6.25% Senior Notes due 2023 (the 2023 Senior Notes) mature on April 1, 2023, and interest is payable semi-annually in arrears on April 1 and October 1 of each year.

2025 Senior Notes. In March 2017, Crestwood Midstream issued $500 million of 5.75% unsecured senior notes due 2025 (the 2025 Senior Notes) in a private offering. The 2025 Senior Notes will mature on April 1, 2025, and interest is payable semi-annually in arrears on April 1 and October 1 of each year, beginning October 1, 2017. The net proceeds from this offering of approximately $492 million were used to repay amounts previously outstanding under CMLP's senior notes due in 2020 and 2022 as discussed below.

In May 2017, Crestwood Midstream filed a registration statement with the SEC under which is offered to exchange new senior notes for any and all outstanding 2025 Senior Notes. Crestwood Midstream completed the exchange offer in July 2017. The terms of the exchange notes are substantially identical to the terms of the 2025 Senior Notes, except that the exchange notes are freely tradable.

In general, each series of Crestwood Midstream's senior notes are fully and unconditionally guaranteed, joint and severally, on a senior unsecured basis by Crestwood Midstream's domestic restricted subsidiaries (other than Finance Corp., which has no assets). The indentures contain customary release provisions, such as (i) disposition of all or substantially all the assets of, or the capital stock of, a guarantor subsidiary to a third person if the disposition complies with the indentures; (ii) designation of a guarantor subsidiary as an unrestricted subsidiary in accordance with its indentures; (iii) legal or covenant defeasance of a series of senior notes, or satisfaction and discharge of the related indenture; and (iv) guarantor subsidiary ceases to guarantee any other indebtedness of Crestwood Midstream or any other guarantor subsidiary, provided it no longer guarantees indebtedness under the CMLP Credit Facility.

The indentures restricts the ability of Crestwood Midstream and its restricted subsidiaries to, among other things, sell assets; redeem or repurchase subordinated debt; make investments; incur or guarantee additional indebtedness or issue preferred units; create or incur certain liens; enter into agreements that restrict distributions or other payments to Crestwood Midstream from its restricted subsidiaries; consolidate, merge or transfer all or substantially all of their assets; engage in affiliate transactions; create unrestricted subsidiaries; and incur a change in control at either Crestwood Equity or Crestwood Midstream, including an acquisition of Crestwood Holdings' ownership of Crestwood Equity's general partner by any third party including Crestwood Holdings' debtors under an event of default of their debt since Crestwood Equity's non-economic general partner interest is pledged as collateral under that debt. These restrictions are subject to a number of exceptions and qualifications, and many of these restrictions will terminate when the senior notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Rating Services and no default or event of default (each as defined in the respective indentures) under the indentures has occurred and is continuing.

At December 31, 2018, Crestwood Midstream was in compliance with the debt covenants and restrictions in each of its credit agreements discussed above.

Crestwood Midstream's Credit Facility and its respective senior notes are secured by its assets and liabilities of the guarantor subsidiaries. Accordingly, such assets are only available to the creditors of Crestwood Midstream. Crestwood Equity had restricted net assets of approximately $2,028.2 million as of December 31, 2018.

Repayments. During the year ended December 31, 2017, Crestwood Midstream paid approximately $349.9 million and $457.8 million to purchase, redeem and/or cancel all of the principal amounts previously outstanding under CMLP's senior notes due in 2020 and 2022, respectively. Crestwood Midstream funded the repayments with a combination of net proceeds from the issuance of the 2025 Senior Notes described above and borrowings under the 2020 Credit Facility. In conjunction with these note repayments, Crestwood Midstream (i) recognized a loss on extinguishment of debt of approximately $37.7 million during the year ended December 31, 2017 (including the write off of approximately $6.8 million of deferred financing costs associated with the senior notes due in 2022); and (ii) paid $5.1 million and $1.0 million of accrued interest on CMLP's senior notes due in 2020 and 2022, respectively, on the date they were tendered.

In June 2016, Crestwood Midstream paid approximately $312.9 million to purchase and cancel approximately $161.2 million and $163.6 million of the principal amounts previously outstanding under CMLP's senior notes due in 2020 and 2022,

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respectively, utilizing a portion of the proceeds received from Stagecoach Gas, as further discussed in Note 6. During the year ended December 31, 2016, Crestwood Midstream recognized a gain on extinguishment of debt of approximately $10.0 million in conjunction with the early tender of these notes. Crestwood Midstream also paid $4.5 million and $2.6 million of accrued interest on CMLP's senior notes due in 2020 and 2022, respectively, on the date they were tendered.

Other Obligations

Our non-interest bearing obligations due under noncompetition agreements consist of agreements between Crestwood Midstream and sellers of certain companies acquired in 2014 with payments due through 2022 and imputed interest ranging from 5.02% to 6.75%. Non-interest bearing obligations consisted of $1.7 million and $2.7 million in total payments due under these agreements, less unamortized discount based on imputed interest of $0.2 million and $0.3 million at December 31, 2018 and 2017, respectively.

Maturities

The aggregate maturities of principal amounts on our outstanding long-term debt and other notes payable as of December 31, 2018 for the next five years and in total thereafter are as follows (in millions):

2019	$0.9
2020	0.2
2021	0.2
2022	0.2
2023	1,278.2
Thereafter	500.0
Total debt	$1,779.7

Residual Value Guarantee

In 2012, Crestwood Equity entered into a support agreement with Suburban Propane Partners, L.P. (SPH) pursuant to which Crestwood Equity is obligated to provide contingent, residual support of approximately $497 million of aggregate principal amount of the 7.5% senior unsecured notes due 2018 of SPH and Suburban Energy Finance Corp. (collectively, the SPH Issuers) or any permitted refinancing thereof. The support agreement was terminated on the maturity date of supported debt.

Note 10 - Earnings Per Limited Partner Unit

Our net income (loss) attributable to Crestwood Equity Partners is allocated to the subordinated and limited partner unitholders based on their ownership percentage after giving effect to net income attributable to the preferred units. We calculate basic net income per limited partner unit using the two-class method. Diluted net income per limited partner unit is computed using the treasury stock method, which considers the impact to net income attributable to Crestwood Equity Partners and limited partner units from the potential issuance of limited partner units.

We exclude potentially dilutive securities from the determination of diluted earnings per unit (as well as their related income statement impacts) when their impact on net income attributable to Crestwood Equity Partners per limited partner unit is anti-dilutive. The following table summarizes information regarding the weighted-average of common units excluded during the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Preferred units [(1)]	7,125,744	7,007,917	6,433,127

Crestwood Niobrara's preferred units[1]	6,526,495	7,146,663	7,548,624
Subordinated units[2]	438,789	438,789	438,789
Stock-based compensation performance units[2]	365,997	316,980	—

(1) See Note 12 for additional information regarding the potential conversion of our preferred units and Crestwood Niobrara's preferred units to common units.

(2) For a description of our subordinated and stock-based compensation performance units, see Note 12 and Note 13, respectively.

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Note 11 - Income Taxes

The (provision) benefit for income taxes for the years ended December 31, 2018, 2017, and 2016 consisted of the following (in millions):

	CEQP Year Ended December 31,			CMLP Year Ended December 31,		
	2018	2017	2016	2018	2017 [1]	2016
Current:						
Federal	$(0.5)	$(1.1)	$(3.2)	$0.1	$ —	$ —
State	(0.3)	(0.2)	(0.2)	(0.2)	—	0.2
Total current	(0.8)	(1.3)	(3.4)	(0.1)	—	0.2
Deferred:						
Federal	0.5	2.1	3.0	—	—	—
State	0.2	—	0.1	0.1	—	(0.2)
Total deferred	0.7	2.1	3.1	0.1	—	(0.2)
(Provision) benefit for income taxes	$(0.1)	$0.8	$(0.3)	$—	$ —	$ —

(1) For the year ended December 31, 2017, our benefit for income taxes was not material to CMLP's consolidated statement of operations.

The effective rate differs from the statutory rate for the years ended December 31, 2018, 2017 and 2016, primarily due to the partnerships not being treated as a corporation for federal income tax purposes as discussed in Note 2.

Deferred income taxes related to CEQP's wholly owned subsidiaries, IPCH Acquisition Corp. and Crestwood Gas Services GP LLC, and our Texas Margin tax which reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

Components of our deferred income taxes at December 31, 2018 and 2017 are as follows (in millions).

	CEQP December 31,		CMLP December 31,	
	2018	2017	2018	2017
Deferred tax asset:				
Basis difference in stock of company	$0.2	$0.2	$—	$—
Total deferred tax asset	0.2	0.2	—	—
Deferred tax liability:				
Basis difference in stock of company	(2.8)	(3.5)	(0.6)	(0.7)
Total deferred tax liability	(2.8)	(3.5)	(0.6)	(0.7)
Net deferred tax liability	$(2.6)	$(3.3)	$(0.6)	$(0.7)

Uncertain Tax Positions. We evaluate the uncertainty in tax positions taken or expected to be taken in the course of preparing our consolidated financial statements to determine whether the tax positions are more likely than not of being sustained by the applicable tax authority. Such tax positions, if any, would be recorded as a tax benefit or expense in the current year. We believe that there were no uncertain tax positions that would impact our results of operations for the years ended December 31, 2018, 2017 and 2016 and that no provision for income tax was required for these consolidated financial statements. However, our conclusions regarding the evaluation of uncertain tax positions are subject to review and may change based on factors including, but not limited to, ongoing analyses of tax laws, regulations and interpretations thereof.

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Note 12 – Partners' Capital

Preferred Units

Subject to certain conditions, the holders of the preferred units will have the right to convert preferred units into (i) common units on a 1-for-10 basis, or (ii) a number of common units determined pursuant to a conversion ratio set forth in our partnership agreement upon the occurrence of certain events, such as a change in control. The preferred units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class, with each preferred units entitled to one vote for each common unit into which such preferred unit is convertible, except that the preferred units are entitled to vote as a separate class on any matter on which all unitholders are entitled to vote that adversely affects the rights, powers, privileges or preferences of the preferred units in relation to CEQP's other securities outstanding.

Common Units

Equity Distribution Agreement. On August 4, 2017, we entered into an equity distribution agreement with certain financial institutions (each, a Manager), under which we may offer and sell from time to time through one or more of the Managers, common units having an aggregate offering price of up to $250 million. Common units sold pursuant to this at-the-market (ATM) equity distribution program are issued under a registration statement that became effective on April 12, 2017. We are required to pay the Managers an aggregate fee of up to 2.0% of the gross sales price per common unit sold under our ATM equity distribution program. There were no units issued under our ATM equity distribution program during the year ended December 31, 2018. During the year ended December 31, 2017, we issued 633,271 common units under the ATM equity distribution program for net proceeds of approximately $15.2 million. We paid a manager fee of approximately $0.3 million during the year ended December 31, 2017 related to the sale of the common units.

Distributions

Crestwood Equity

Limited Partners. Crestwood Equity makes quarterly distributions to its partners within approximately 45 days after the end of each quarter in an aggregate amount equal to its available cash for such quarter. Available cash generally means, with respect to each 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 its business;
- comply with applicable law, any of its debt instruments, or other agreements; or
- provide funds for distributions to unitholders for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. The amount of cash CEQP has available for distribution depends primarily upon its cash flow (which consists of the cash distributions it receives in connection with its ownership of Crestwood Midstream).

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A summary of CEQP's limited partner quarterly cash distributions for the years ended December 31, 2018, 2017 and 2016 is presented below:

Record Date	Payment Date	Per Unit Rate	Cash Distributions (in millions)
2018			
February 7, 2018	February 14, 2018	$0.60	$ 42.7
May 8, 2018	May 15, 2018	$0.60	42.7
August 7, 2018	August 14, 2018	$0.60	42.7
November 7, 2018	November 14, 2018	$0.60	42.7
			$ 170.8
2017			
February 7, 2017	February 14, 2017	$0.60	$ 41.8
May 8, 2017	May 15, 2017	$0.60	41.8
August 7, 2017	August 14, 2017	$0.60	41.8
November 7, 2017	November 14, 2017	$0.60	42.2
			$ 167.6
2016			
February 5, 2016	February 12, 2016	$1.375	$ 95.6
May 6, 2016	May 13, 2016	$0.60	41.4
August 5, 2016	August 12, 2016	$0.60	41.4
November 7, 2016	November 14, 2016	$0.60	41.4
			$ 219.8

On February 14, 2019, we paid a distribution of $0.60 per limited partner unit to unitholders of record on February 7, 2019 with respect to the fourth quarter of 2018.

Preferred UnitHolders. The holders of our preferred units are entitled to receive fixed quarterly distributions of $0.2111 per unit. Through the quarters 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. We paid distributions on our preferred units through the issuance of additional preferred units through and for the quarter ended June 30, 2017. 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 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 unitholders. If we fail to pay the full amount payable to our preferred unitholders 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.

During the year ended December 31, 2018, we made cash distributions to our preferred unitholders of approximately $60.1 million. In November 2017, we made a cash distribution to our preferred unitholders of approximately $15.0 million for the quarter ended September 30, 2017. During the years ended December 31, 2017 and 2016, we issued 4,724,030 and 5,815,170 preferred units to our preferred unitholders in lieu of paying quarterly cash distributions of

$43.1 million and $53.0 million. On February 14, 2019, we made a cash distribution of approximately $15.0 million to our preferred unitholders for the quarter ended December 31, 2018.

In March 2018, Crestwood Equity registered 71,257,445 preferred units under a shelf registration statement filed with the SEC under which holders of the preferred units may sell their preferred units. The registration statement became effective in May 2018.

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Crestwood Midstream

In accordance with the partnership agreement, Crestwood Midstream's general partner may, from time to time, cause Crestwood Midstream to make cash distributions at the sole discretion of the general partner. During the years ended December 31, 2018, 2017 and 2016, Crestwood Midstream made distributions of $238.4 million, $174.0 million and $227.6 million, which represented net amounts due to Crestwood Midstream related to cash advances to CEQP for its general corporate activities.

Non-Controlling Partner

Crestwood Niobrara issued a preferred interest (Series A Preferred Units) to a subsidiary of General Electric Capital Corporation and GE Structured Finance, Inc. (collectively, GE) in conjunction with the acquisition of its investment in Jackalope, which is reflected as non-controlling interest in our consolidated financial statements. In December 2017, Crestwood Niobrara redeemed 100% of the outstanding Series A Preferred Units from GE for an aggregate purchase price of approximately $202.7 million and issued $175 million in new preferred interests (Series A-2 Preferred Units) to CN Jackalope Holdings LLC (Jackalope Holdings). In conjunction with the issuance of the Series A-2 Preferred Units, we entered into a Second Amended and Restated Limited Liability Company Agreement (Crestwood Niobrara Amended Agreement) with Crestwood Niobrara. Pursuant to the Crestwood Niobrara Amended Agreement, we serve as the managing member of Crestwood Niobrara and, subject to certain restrictions, we have the ability to redeem the Series A-2 Preferred Units for an amount in cash or CEQP common units equal to an amount necessary for Jackalope Holdings to achieve a certain rate of return. Also in conjunction with the Crestwood Niobrara Amended Agreement, we entered into a registration rights agreement with Jackalope Holdings. Pursuant to the registration rights agreement, we granted Jackalope Holdings certain rights with respect to CEQP's common units issuable to Jackalope Holdings in certain circumstances as set forth in the Crestwood Niobrara Amended Agreement. During the years ended December 31, 2018, 2017, and 2016, net income attributable to non-controlling partners was approximately $16.2 million, $25.3 million and $24.2 million.

Crestwood Niobrara is required to make quarterly cash distributions on its preferred interest within 30 days after the end of each quarter. During the years ended December 31, 2018, 2017 and 2016, Crestwood Niobrara paid cash distributions of $9.9 million, $15.2 million and $15.2 million to its preferred interest owners. In January 2019, Crestwood Niobrara paid a cash distribution of $3.3 million to Jackalope Holdings for the quarter ended December 31, 2018.

Other Partners' Capital Transactions

Subordinated Units

In conjunction with Crestwood Holdings' acquisition of Crestwood Equity's general partner, Crestwood Equity issued 438,789 subordinated units, which are considered limited partnership interests, and have the same rights and obligations as its common units, except that the subordinated units are entitled to receive distributions of available cash for a particular quarter only after each of our common units has received a distribution of at least $1.30 for that quarter. The subordinated units convert to common units after (i) CEQP's common units have received a cumulative distribution in excess of $5.20 during a consecutive four quarter period; and (ii) its Adjusted Operating Surplus (as defined in the agreement) exceeds the distribution on a fully dilutive basis.

Note 13 - Equity Plans

Long-term incentive awards are granted under the Crestwood Equity Partners LP Long Term Incentive Plan (Crestwood LTIP) in order to align the economic interests of key employees and directors with those of CEQP’s common unitholders and to provide an incentive for continuous employment. Long-term incentive compensation consist of grants of restricted, phantom and performance units which vest based upon continued service.

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The following table summarizes information regarding restricted and phantom unit activity during the years ended December 31, 2018, 2017 and 2016.

	Units	Weighted-Average Grant Date Fair Value
Unvested - January 1, 2016	466,214	$ 69.80
Granted - restricted units	1,067,535	$ 14.58
Granted - phantom units	17,467	$ 15.54
Vested - restricted units	(193,295)	$ 76.82
Forfeited	(65,591)	$ 25.13
Unvested - December 31, 2016	1,292,330	$ 24.67
Granted - restricted units	919,411	$ 25.69
Granted - phantom units	15,849	$ 25.02
Granted - performance units	405,620	$ 30.21
Vested - restricted units	(607,115)	$ 28.00
Vested - performance units	(31,106)	$ 30.27
Forfeited - restricted units	(140,137)	$ 23.73
Forfeited - performance units	(24,756)	$ 30.45
Unvested - December 31, 2017	1,830,096	$ 25.21
Granted - restricted units	1,144,017	$ 25.80
Granted - phantom units	7,750	$ 26.10
Granted - performance units	901	$ 25.60
Vested - restricted units	(617,807)	$ 23.73
Vested - phantom units	(105,809)	$ 49.45
Vested - performance units	(11,772)	$ 28.87
Forfeited - restricted units	(53,530)	$ 23.36
Forfeited - phantom units	(6)	$ 49.45
Forfeited - performance units	(5,870)	$ 30.45
Unvested - December 31, 2018	2,187,970	$ 24.78

As of December 31, 2018 and 2017, we had total unamortized compensation expense of approximately $28.0 million and $23.7 million related to restricted, phantom, and performance units, which will be amortized during the next three years (or sooner in certain cases, which generally represents the original vesting period of these instruments), except for grants to non-employee directors of our general partner, which vest over one year. We recognized compensation expense of approximately $24.3 million, $22.4 million and $16.0 million under the Crestwood LTIP during the years ended December 31, 2018, 2017 and 2016, which is included in general and administrative expenses on our consolidated statements of operations. As of February 11, 2019, we had 4,036,711 units available for issuance under the Crestwood LTIP.

Restricted Units. Under the Crestwood LTIP, participants who have been granted restricted units may elect to have us withhold common units to satisfy minimum statutory tax withholding obligations arising in connection with the vesting of non-vested common units. Any such common units withheld are returned to the Crestwood LTIP on the applicable vesting dates, which correspond to the times at which income is recognized by the employee. When we withhold these common units, we are required to remit to the appropriate taxing authorities the fair value of the units withheld as of the vesting date. The number of units withheld is determined based on the closing price per common unit as reported on the NYSE on such dates. During the years ended December 31, 2018, 2017, and 2016 we withheld 221,576, 206,600 and 57,508 common units to satisfy employee tax withholding obligations.

Phantom Units. The Crestwood LTIP permits grants of phantom units that entitle the holder thereof to receive upon vesting one CEQP common unit granted pursuant to the Crestwood LTIP and a phantom unit award agreement (the Crestwood Equity Phantom Unit Agreement). The Crestwood Equity Phantom Unit Agreement provides for vesting to occur at the end of three years following the grant date or, if earlier, upon the named executive officer’s termination without cause or due to death or disability or the named executive officer’s resignation for employee cause (each, as defined in the Crestwood Equity Phantom Unit Agreement). In addition, the Crestwood Equity Phantom Unit Agreement provides for distribution equivalent rights with

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respect to each phantom unit which are paid in additional phantom units and settled in common units upon vesting of the underlying phantom units.

Performance Units. The Crestwood LTIP permits grants of performance units that are designed to provide an incentive for continuous employment to certain key employees. Performance units vest over a three year performance period and the number of units issued are 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. The performance goals are 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. The vesting of performance units is subject to the attainment of certain performance and market goals over a three year period and entitle a participant to receive common units of Crestwood Equity without payment of an exercise price upon vesting.

Employee Unit Purchase Plan

In August 2018, the board of directors of our general partner approved an employee unit purchase plan under which employees of the general partner may purchase our common units through payroll deductions up to a maximum of 10% of the employees' eligible compensation, not to exceed $25,000 for any calendar year. Under the plan, we anticipate purchasing our common units on the open market for the benefit of participating employees based on their payroll deductions. In addition, we may match up to 10% of participating employees' payroll deductions to purchase additional Crestwood common units for participating employees. The board of directors of our general partner authorized 1,500,000 common units (subject to adjustment as provided in the employee unit purchase plan) to be available for purchase. There were no common units purchased under the employee unit purchase plan in 2018.

Note 14 - Employee Benefit Plan

A 401(k) plan is available to all of our employees after meeting certain requirements. The plan permits employees to make contributions up to 90% of their salary, up to statutory limits, which was $18,500 in 2018, and $18,000 in 2017 and 2016. We match 100% of participants basic contribution up to 6% of eligible compensation. Employees may participate in the plans immediately and certain employees are not eligible for matching contributions until after a 90-day waiting period. Aggregate matching contributions made by us were $4.6 million, $4.0 million and $3.8 million during the years ended December 31, 2018, 2017 and 2016.

Note 15 – Commitments and Contingencies

Legal Proceedings

California Trucking Lawsuit. On March 13, 2017, a former Crestwood truck driver filed a lawsuit in the Superior Court (the Court) for Kern County, California on behalf of all Crestwood Transportation LLC's California drivers alleging that Crestwood Equity and its officers, directors and employees violated the California wage and hour laws by failing to comply with certain requirements of the laws. The settlement of this lawsuit was finalized in November 2018, and it did not have a material impact to our consolidated financial statements.

General. We are periodically involved in litigation proceedings. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, then we accrue the estimated amount. The results of litigation proceedings cannot be predicted with certainty. We could incur judgments, enter into settlements or revise our expectations regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations or cash flows in the period in which the amounts are paid and/or accrued. As of

December 31, 2018 and 2017, both CEQP and CMLP had $0.1 million and approximately $2.1 million accrued for outstanding legal matters. Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures for which we can estimate will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures.

Any loss estimates are inherently subjective, based on currently available information, and are subject to management's judgment and various assumptions. Due to the inherently subjective nature of these estimates and the uncertainty and unpredictability surrounding the outcome of legal proceedings, actual results may differ materially from any amounts that have been accrued.

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Regulatory Compliance

In the ordinary course of our business, we are subject to various laws and regulations. In the opinion of our management, compliance with current laws and regulations will not have a material effect on our results of operations, cash flows or financial condition.

Environmental Compliance

Our operations are subject to stringent and complex laws and regulations pertaining to worker health, safety, and the environment. We are subject to laws and regulations at the federal, state, regional and local levels that relate to air and water quality, hazardous and solid waste management and disposal and other environmental matters. The cost of planning, designing, constructing and operating our facilities must incorporate compliance with environmental laws and regulations and worker safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures.

During 2014, we experienced three releases totaling approximately 28,000 barrels of produced water on our Arrow water gathering system located on the Fort Berthold Indian Reservation in North Dakota. We immediately notified the National Response Center, the Three Affiliated Tribes and numerous other regulatory authorities. Thereafter, we contained and cleaned up the releases, and placed the impacted segments of these water lines back into service. In May 2015, we experienced a release of approximately 5,200 barrels of produced water on our Arrow water gathering system, immediately notified numerous regulatory authorities and other third parties, and thereafter contained and cleaned up the releases.

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 on September 15, 2015. Our discussions regarding the notice of violation continue with the Three Affiliated Tribes.

We will continue our remediation efforts to ensure the impacted lands are restored to their prior state. We believe these releases are insurable events under our policies, and we have notified our carriers of these events. We have not recorded an insurance receivable as of December 31, 2018.

At December 31, 2018 and 2017, our accrual of approximately $1.8 million and $1.9 million is based on our undiscounted estimate of amounts we will spend on remediation and compliance with environmental and other regulations, and any associated fines or penalties (including the Arrow water releases described above). We estimate that our potential liability for reasonably possible outcomes related to our environmental exposures could range from approximately $1.8 million to $3.3 million at December 31, 2018.

Self-Insurance

We utilize third-party insurance subject to varying retention levels of self-insurance, which management considers prudent. Such self-insurance relates to losses and liabilities primarily associated with medical claims, workers' compensation claims and general, product, vehicle and environmental liability. Losses are accrued based upon management's estimates of the aggregate liability for claims incurred using certain assumptions followed in the insurance industry and based on past experience. The primary assumption utilized is actuarially determined loss development factors. The loss development factors are based primarily on historical data. Our self insurance reserves could be affected if future claim developments differ from the historical trends. We believe changes in health care costs, trends in health care claims of our employee base, accident frequency and severity and other factors could materially affect the estimate for these liabilities. We continually monitor changes in employee demographics, incident and claim type and evaluate our insurance accruals and adjust our accruals based on our evaluation of these qualitative data points. We are liable for the development of claims for our disposed retail propane operations, provided they were reported prior to August 1, 2012. The following table summarizes CEQP’s and CMLP’s self-insurance reserves at December 31, 2018 and 2017 (in millions):

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	CEQP December 31,		CMLP December 31,	
	2018	2017	2018	2017
Self-insurance reserves (1)	$11.3	$13.6	$9.6	$11.6

(1) CEQP and CMLP classified approximately $7.5 million and $6.2 million of their respective balances as other long-term liabilities on their consolidated balance sheets at December 31, 2018.

Commitments and Purchase Obligations

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office buildings, crude oil railroad cars and other operating facilities and equipment. The terms of the agreements vary from 2019 until 2032. Our rent expense for operating leases for the years ended December 31, 2018, 2017 and 2016, totaled $13.9 million, $34.2 million and $25.5 million.

Capital Leases. We also maintain capital leases in the ordinary course of our business activities. These leases primarily related to certain of our vehicle leases.

The following table presents the future minimum lease payments under our noncancelable operating leases and the net minimum lease payments under our existing capital leases for the next five years ending December 31 and in total thereafter (in millions):

		Capital Leases			
Year Ending December 31,	Operating Leases	Minimum Lease Payments	Less Interest	Net Present Value	Total
2019	$ 22.3	$3.0	$ 0.6	$ 2.4	$24.7
2020	18.1	3.3	0.4	2.9	21.0
2021	14.4	3.2	0.2	3.0	17.4
2022	9.7	1.9	0.1	1.8	11.5
2023	6.0	—	—	—	6.0
Thereafter	10.7	—	—	—	10.7
Total minimum lease payments	$ 81.2	$11.4	$ 1.3	$ 10.1	$91.3

Purchase Commitments. We periodically enter into agreements with suppliers to purchase fixed quantities of NGLs, distillates, crude oil and natural gas at fixed prices. At December 31, 2018, the total of these firm purchase commitments was $894.0 million, of which approximately $784.3 million will occur over the course of the next twelve months. We also enter into non-binding agreements with suppliers to purchase quantities of NGLs, distillates and natural gas at variable prices at future dates at the then prevailing market prices.

We have entered into certain purchase commitments primarily related to our gathering and processing segment. At December 31, 2018, our total purchase commitments were approximately $77.2 million, which primarily relate to future growth projects and maintenance obligations in our gathering and processing segment. The purchases associated with these commitments are expected to occur over the next twelve months.

Guarantees and Indemnifications. We are involved in various joint ventures that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. For a further description of our guarantees associated with our joint ventures, see Note 6.

Our potential exposure under guarantee and indemnification arrangements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim, specificity as to duration, and the particular transaction. As of December 31, 2018, we have no amounts accrued for these guarantees.

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Note 16 – Related Party Transactions

Crestwood Holdings indirectly owns both CEQP's and CMLP's general partner. The affiliates of Crestwood Holdings and its owners are considered CEQP's and CMLP's related parties. We enter into transactions with our affiliates within the ordinary course of business and the services are based on the same terms as non-affiliates, including gas gathering and processing services under long-term contracts, product purchases and various operating agreements. We also enter into transactions with our affiliates related to services provided on our expansion projects. During the year ended December 31, 2018 and 2017, we paid approximately $7.2 million and $2.5 million of capital expenditures to Applied Consultants, Inc., an affiliate of Crestwood Holdings. Below is a discussion of certain of our related party agreements.

Shared Services. CMLP shares common management, general and administrative and overhead costs with CEQP. CEQP grants long-term incentive awards under the Crestwood LTIP as discussed in Note 13 and, as such, CEQP allocates a portion of its unit-based compensation costs to CMLP.

Stagecoach Gas Management Agreement. In May 2016, Crestwood Midstream Operations, LLC (Crestwood Midstream Operations), our wholly-owned subsidiary and Stagecoach Gas entered into a management agreement under which Crestwood Midstream Operations provides the management and operating services required by Stagecoach Gas' facilities. The initial term of the agreement will expire in May 2021, and is automatically extended for three-year periods unless otherwise terminated pursuant to the terms of the agreement. Reimbursements received from Stagecoach Gas under this agreement are reflected as operations and maintenance expenses at CEQP and CMLP in the table below.

Tres Palacios Operating Agreement. A consolidated subsidiary of Crestwood Midstream entered into an operating agreement with Tres Palacios, pursuant to which we assumed the responsibility of operating and maintaining the facilities as well as certain administrative and other general services identified in the agreement. Under the operating agreement, Tres Palacios reimburses us for all cost incurred on its behalf. These reimbursements are reflected as operations and maintenance expenses at CEQP and CMLP in the table below.

Crestwood Permian Operating Agreement. In October 2016, Crestwood Midstream Operations entered into an operating agreement with Crestwood Permian, pursuant to which we provide operating services for Crestwood Permian's facilities, as well as certain administrative and other general services identified in the agreement. Under this operating agreement, Crestwood Permian reimburses us for all costs incurred on its behalf. These reimbursements are reflected as operations and maintenance expenses at CEQP and CMLP in the table below.

Jackalope Gas Gathering Services, L.L.C. A consolidated subsidiary of Crestwood Midstream entered into a marketing services agreement with Jackalope under which we provide marketing services for Jackalope as well as certain administrative and other general services identified in the agreement. Under this marketing services agreement, Jackalope reimburses us for all costs incurred on its behalf. These reimbursements are reflected as operations and maintenance expenses at CEQP and CMLP in the table below.

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The following table shows revenues, costs of product/services sold, general and administrative expenses and reimbursement of expenses from our affiliates for the years December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31, 2018	2017	2016
Revenues at CEQP and CMLP	$ 1.0	$ 1.8	$ 2.6
Costs of product/services sold at CEQP and CMLP(1)	$ 134.7	$ 15.3	$ 17.7
Operations and maintenance expenses at CEQP and CMLP(2)	$ 28.7	$ 22.3	$ 8.1
General and administrative expenses charged by CEQP to CMLP, net(3)	$ 20.7	$ 19.4	$ 13.0
General and administrative expenses at CEQP charged from Crestwood Holdings, net(4)	$ (2.7)	$ (1.7)	$ (2.2)

(1) Includes $56.1 million during the year ended December 31, 2018 related to purchases of NGLs from a subsidiary of Crestwood Permian and $78.6 million related to an agency marketing agreement with Ascent Resources - Utica, LLC (Ascent). Amounts presented for the years ended December 31, 2017 and 2016 represent natural gas purchases from Sabine Oil and Gas (Sabine). Ascent and Sabine are affiliates of Crestwood Holdings for the respective periods presented.

(2) We have operating agreements with certain of our unconsolidated affiliates pursuant to which we charge them operations and maintenance expenses in accordance with their respective agreements. During the year ended December 31, 2018, we charged $7.9 million to Stagecoach Gas, $3.8 million to Tres Palacios, $15.9 million to Crestwood Permian and $1.1 million to Jackalope. During the year ended December 31, 2017, we charged $8.4 million to Stagecoach Gas, $3.5 million to Tres Palacios, $10.0 million to Crestwood Permian and $0.4 million to Jackalope. During the year ended December 31, 2016, we charged $5.0 million to Stagecoach Gas, $2.7 million to Tres Palacios, and $0.4 million to Jackalope.

(3) Includes $24.3 million, $22.4 million and $16.0 million of net unit-based compensation charges allocated from CEQP to CMLP for the years ended December 31, 2018, 2017 and 2016. In addition, includes $3.6 million, $3.0 million and $3.0 million of CMLP's general and administrative costs allocated to CEQP during the years ended December 31, 2018, 2017 and 2016.

(4) Includes $4.2 million, $3.1 million and $3.2 million of unit-based compensation charges allocated from Crestwood Holdings to CEQP and CMLP during the years ended December 31, 2018, 2017 and 2016.

The following table shows accounts receivable and accounts payable from our affiliates as of December 31, 2018 and 2017 (in millions):

	December 31, 2018	2017
Accounts receivable at CEQP and CMLP	$4.1	$7.1
Accounts payable at CEQP	$16.1	$7.4

Accounts payable at CMLP	$13.6	$5.0

Note 17 – Segments

Financial Information

We have three operating and reportable segments: (i) gathering and processing operations; (ii) storage and transportation operations; and (iii) marketing, supply and logistics operations. Our corporate operations include all general and administrative expenses that are not allocated to our reportable segments. For a further description of our operating and reporting segments, see Note 1. We assess the performance of our operating segments based on EBITDA, which is defined as income before income taxes, plus debt-related costs (net interest and debt expense and gain or loss on modification/extinguishment of debt) and depreciation, amortization and accretion expense.

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Below is a reconciliation of CEQP's net income (loss) to EBITDA (in millions):

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$67.0	$(166.6)	$(192.1)
Add:			
Interest and debt expense, net	99.2	99.4	125.1
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)
Provision (benefit) for income taxes	0.1	(0.8)	0.3
Depreciation, amortization and accretion	168.7	191.7	229.6
EBITDA	$335.9	$161.4	$152.9

Below is a reconciliation of CMLP's net income (loss) to EBITDA (in millions):

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$58.6	$(175.5)	$(197.5)
Add:			
Interest and debt expense, net	99.2	99.4	125.1
(Gain) loss on modification/extinguishment of debt	0.9	37.7	(10.0)
Depreciation, amortization and accretion	181.4	202.7	240.5
EBITDA	$340.1	$164.3	$158.1

The following tables summarize CEQP's and CMLP's reportable segment data for the years ended December 31, 2018, 2017 and 2016 (in millions). Intersegment revenues included in the following tables are accounted for as arms-length transactions that apply our revenue recognition policies described in Note 2. Included in earnings from unconsolidated affiliates below was approximately $42.3 million, $32.5 million and $29.6 million of depreciation and amortization expense and gains (losses) on long-lived assets, net related to our equity investments for the years ended December 31, 2018, 2017 and 2016, respectively.

Crestwood Equity

	Year Ended December 31, 2018				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$946.7	$ 17.1	$2,690.3	$ —	$3,654.1
Intersegment revenues	192.4	10.5	(202.9)	—	—
Costs of product/services sold	767.0	0.2	2,362.2	—	3,129.4
Operations and maintenance expense	71.7	3.3	50.8	—	125.8
General and administrative expense	—	—	—	88.1	88.1
Gain (loss) on long-lived assets, net	(3.0)	—	(27.3)	1.7	(28.6)
Earnings from unconsolidated affiliates, net	22.5	30.8	—	—	53.3
Other income, net	—	—	—	0.4	0.4
EBITDA	$319.9	$ 54.9	$47.1	$ (86.0)	$335.9
Goodwill	$45.9	$ —	$92.7	$ —	$138.6
Total assets	$2,633.4	$ 1,004.4	$612.5	$ 44.2	$4,294.5
Purchases of property, plant and equipment	$294.7	$ 0.6	$5.6	$ 4.6	$305.5

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	Year Ended December 31, 2017				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$1,688.2	$ 37.2	$2,155.5	$ —	$3,880.9
Intersegment revenues	134.5	6.7	(141.2)	—	—
Costs of product/services sold	1,480.8	0.3	1,893.6	—	3,374.7
Operations and maintenance expense	68.4	4.2	63.4	—	136.0
General and administrative expense	—	—	—	96.5	96.5
Loss on long-lived assets, net	(14.4)	—	(48.2)	(3.0)	(65.6)
Goodwill impairment	—	—	(38.8)	—	(38.8)
Loss on contingent consideration	—	(57.0)	—	—	(57.0)
Earnings from unconsolidated affiliates, net	18.9	28.9	—	—	47.8
Other income, net	0.8	—	—	0.5	1.3
EBITDA	$278.8	$ 11.3	$(29.7)	$ (99.0)	$161.4
Goodwill	$45.9	$ —	$101.7	$ —	$147.6
Total assets	$2,474.1	$ 1,040.6	$757.1	$ 13.1	$4,284.9
Purchases of property, plant and equipment	$162.7	$ 1.3	$17.7	$ 6.7	$188.4

	Year Ended December 31, 2016				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$1,118.8	$ 165.3	$1,236.4	$ —	$2,520.5
Intersegment revenues	108.6	4.2	(112.8)	—	—
Costs of product/services sold	917.0	5.1	1,003.0	—	1,925.1
Operations and maintenance expense	77.0	21.4	59.7	—	158.1
General and administrative expense	—	—	—	88.2	88.2
Loss on long-lived assets	(2.0)	(32.2)	(31.4)	—	(65.6)
Goodwill impairment	(8.6)	(44.9)	(109.1)	—	(162.6)
Earnings from unconsolidated affiliates, net	20.3	11.2	—	—	31.5
Other income, net	—	—	—	0.5	0.5
EBITDA	$243.1	$ 77.1	$(79.6)	$ (87.7)	$152.9
Purchases of property, plant and equipment	$76.6	$ 3.3	$19.1	$ 1.7	$100.7

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Crestwood Midstream

	Year Ended December 31, 2018				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$946.7	$ 17.1	$2,690.3	$ —	$3,654.1
Intersegment revenues	192.4	10.5	(202.9)	—	—
Costs of product/services sold	767.0	0.2	2,362.2	—	3,129.4
Operations and maintenance expense	71.7	3.3	50.8	—	125.8
General and administrative expense	—	—	—	83.5	83.5
Gain (loss) on long-lived assets, net	(3.0)	—	(27.3)	1.7	(28.6)
Earnings from unconsolidated affiliates, net	22.5	30.8	—	—	53.3
EBITDA	$319.9	$ 54.9	$47.1	$ (81.8)	$340.1
Goodwill	$45.9	$ —	$92.7	$ —	$138.6
Total assets	$2,807.1	$ 1,004.4	$612.5	$ 38.0	$4,462.0
Purchases of property, plant and equipment	$294.7	$ 0.6	$5.6	$ 4.6	$305.5

	Year Ended December 31, 2017				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$1,688.2	$ 37.2	$2,155.5	$ —	$3,880.9
Intersegment revenues	134.5	6.7	(141.2)	—	—
Costs of product/services sold	1,480.8	0.3	1,893.6	—	3,374.7
Operations and maintenance expense	68.4	4.2	63.4	—	136.0
General and administrative expense	—	—	—	93.1	93.1
Loss on long-lived assets, net	(14.4)	—	(48.2)	(3.0)	(65.6)
Goodwill impairment	—	—	(38.8)	—	(38.8)
Loss on contingent consideration	—	(57.0)	—	—	(57.0)
Earnings from unconsolidated affiliates, net	18.9	28.9	—	—	47.8
Other income, net	0.8	—	—	—	0.8
EBITDA	$278.8	$ 11.3	$(29.7)	$ (96.1)	$164.3
Goodwill	$45.9	$ —	$101.7	$ —	$147.6
Total assets	$2,662.0	$ 1,040.6	$757.1	$ 6.6	$4,466.3
Purchases of property, plant and equipment	$162.7	$ 1.3	$17.7	$ 6.7	$188.4

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	Year Ended December 31, 2016				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Corporate	Total
Revenues	$1,118.8	$ 165.3	$1,236.4	$ —	$2,520.5
Intersegment revenues	108.6	4.2	(112.8)	—	—
Costs of product/services sold	917.0	5.1	1,003.0	—	1,925.1
Operations and maintenance expense	77.0	18.3	59.7	—	155.0
General and administrative expense	—	—	—	85.6	85.6
Loss on long-lived assets, net	(2.0)	(32.2)	(31.4)	—	(65.6)
Goodwill impairment	(8.6)	(44.9)	(109.1)	—	(162.6)
Earnings from unconsolidated affiliates, net	20.3	11.2	—	—	31.5
EBITDA	$243.1	$ 80.2	$(79.6)	$ (85.6)	$158.1
Purchases of property, plant and equipment	$76.6	$ 3.3	$19.1	$ 1.7	$100.7

In conjunction with the adoption of the provisions of Topic 606, we began reporting our revenues from contracts with customers disaggregated by type of product/service sold and by commodity type for each of our segments for the year ended December 31, 2018 as we believe it best depicts how the nature, amount, timing and uncertainty of our revenues and cash flows are affected by economic factors. See details in the table below for disaggregation of our revenues (in millions).

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	Year Ended December 31, 2018				
	Gathering and Processing	Storage and Transportation	Marketing, Supply and Logistics	Intersegment Elimination	Total
Revenues:					
Topic 606 revenues					
Gathering					
Natural gas	$134.9	$ —	$ —	$ —	$134.9
Crude oil	38.8	—	—	—	38.8
Water	58.0	—	—	—	58.0
Processing					
Natural gas	10.7	—	—	—	10.7
NGLs	—	—	6.1	—	6.1
Compression					
Natural gas	29.1	—	—	—	29.1
Storage					
Crude oil	1.8	4.2	—	(1.5)	4.5
NGLs	—	—	8.6	—	8.6
Pipeline					
Crude oil	—	7.1	—	(2.3)	4.8
Transportation					
Crude oil	2.9	—	5.9	—	8.8
NGLs	—	—	26.9	—	26.9
Water	—	—	0.3	—	0.3
Rail Loading					
Crude oil	—	14.3	0.2	(5.2)	9.3
NGLs	—	—	3.1	—	3.1
Product Sales					
Natural gas	55.8	—	70.9	(16.6)	110.1
Crude oil	722.9	—	978.0	(151.3)	1,549.6
NGLs	84.2	—	1,247.0	(24.5)	1,306.7
Other	—	2.0	—	(1.5)	0.5
Total Topic 606 revenues	1,139.1	27.6	2,347.0	(202.9)	3,310.8
Non-Topic 606 revenues[(1)]	—	—	343.3	—	343.3
Total revenues	$1,139.1	$ 27.6	$ 2,690.3	$ (202.9)	$3,654.1

(1) Represents revenues related to our commodity-based derivatives. See Note 7 for additional information related to our price risk management activities.

Major Customers

No customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2018, 2017 or 2016 at CEQP or CMLP.

Note 18 – Crestwood Midstream Condensed Consolidating Financial Information

Crestwood Midstream is a holding company (Parent) and owns no operating assets and has no significant operations independent of its subsidiaries. Obligations under Crestwood Midstream's senior notes and its credit facility are jointly and severally guaranteed by substantially all of its subsidiaries, except for Crestwood Infrastructure, Crestwood Niobrara, Crestwood Northeast, PRBIC and Tres Holdings and their respective subsidiaries (collectively, Non-Guarantor Subsidiaries). Crestwood Midstream Finance Corp., the co-issuer of its senior notes, is Crestwood Midstream's 100% owned subsidiary and has no material assets, operations, revenues or cash flows other than those related to its service as co-issuer of the Crestwood Midstream senior notes.

The tables below present condensed consolidating financial statements for Crestwood Midstream as Parent on a stand-alone, unconsolidated basis, and Crestwood Midstream's combined guarantor and combined non-guarantor subsidiaries as of and for the years ended December 31, 2018, 2017 and 2016. The financial information may not necessarily be indicative of the results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

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Crestwood Midstream Partners LP
Condensed Consolidating Balance Sheet
December 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash	$0.2	$ —	$ —	$ —	$ 0.2
Restricted cash	16.3	—	—	—	16.3
Accounts receivable	—	246.3	19.9	(16.3)	249.9
Inventory	—	64.6	—	—	64.6
Other current assets	—	46.0	—	—	46.0
Total current assets	16.5	356.9	19.9	(16.3)	377.0
Property, plant and equipment, net	—	2,202.3	—	—	2,202.3
Goodwill and intangible assets, net	—	692.4	—	—	692.4
Investments in consolidated affiliates	3,800.4	—	—	(3,800.4)	—
Investments in unconsolidated affiliates	—	—	1,188.2	—	1,188.2
Other non-current assets	—	2.1	—	—	2.1
Total assets	$3,816.9	$ 3,253.7	$ 1,208.1	$ (3,816.7)	$ 4,462.0
Liabilities and partners' capital					
Current liabilities:					
Accounts payable	$16.3	$ 210.5	$ —	$ (16.3)	$ 210.5
Other current liabilities	20.0	81.8	16.2	—	118.0
Total current liabilities	36.3	292.3	16.2	(16.3)	328.5
Long-term liabilities:					
Long-term debt, less current portion	1,752.4	—	—	—	1,752.4
Other long-term liabilities	—	114.0	57.0	—	171.0
Deferred income taxes	—	0.6	—	—	0.6
Partners' capital	2,028.2	2,846.8	953.6	(3,800.4)	2,028.2
Interest of non-controlling partner in subsidiary	—	—	181.3	—	181.3
Total partners' capital	2,028.2	2,846.8	1,134.9	(3,800.4)	2,209.5
Total liabilities and partners' capital	$3,816.9	$ 3,253.7	$ 1,208.1	$ (3,816.7)	$ 4,462.0

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Crestwood Midstream Partners LP
Condensed Consolidating Balance Sheet
December 31, 2017
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash	$1.0	$ —	$ —	$ —	$ 1.0
Accounts receivable	—	439.7	2.9	—	442.6
Inventory	—	68.4	—	—	68.4
Other current assets	—	18.1	—	—	18.1
Total current assets	1.0	526.2	2.9	—	530.1
Property, plant and equipment, net	—	2,007.5	—	—	2,007.5
Goodwill and intangible assets, net	—	743.3	—	—	743.3
Investments in consolidated affiliates	3,705.4	—	—	(3,705.4)	—
Investments in unconsolidated affiliates	—	—	1,183.0	—	1,183.0
Other non-current assets	—	2.4	—	—	2.4
Total assets	$3,706.4	$ 3,279.4	$ 1,185.9	$ (3,705.4)	$ 4,466.3
Liabilities and partners' capital					
Current liabilities:					
Accounts payable	$—	$ 346.8	$ —	$ —	$ 346.8
Other current liabilities	20.5	134.0	—	—	154.5
Total current liabilities	20.5	480.8	—	—	501.3
Long-term liabilities:					
Long-term debt, less current portion	1,490.5	0.8	—	—	1,491.3
Other long-term liabilities	—	45.6	57.0	—	102.6
Deferred income taxes	—	0.7	—	—	0.7
Partners' capital	2,195.4	2,751.5	953.9	(3,705.4)	2,195.4
Interest of non-controlling partner in subsidiary	—	—	175.0	—	175.0
Total partners' capital	2,195.4	2,751.5	1,128.9	(3,705.4)	2,370.4
Total liabilities and partners' capital	$3,706.4	$ 3,279.4	$ 1,185.9	$ (3,705.4)	$ 4,466.3

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Crestwood Midstream Partners LP
Condensed Consolidating Statements of Operations
Year Ended December 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 3,654.1	$ —	$ —	$ 3,654.1
Costs of product/services sold	—	3,129.4	—	—	3,129.4
Operating expenses and other:					
Operations and maintenance	—	125.8	—	—	125.8
General and administrative	55.1	28.4	—	—	83.5
Depreciation, amortization and accretion	—	181.4	—	—	181.4
Loss on long-lived assets, net	—	28.6	—	—	28.6
	55.1	364.2	—	—	419.3
Operating income (loss)	(55.1)	160.5	—	—	105.4
Earnings from unconsolidated affiliates, net	—	—	53.3	—	53.3
Interest and debt expense, net	(99.2)	—	—	—	(99.2)
Loss on modification/extinguishment of debt	(0.9)	—	—	—	(0.9)
Equity in net income (loss) of subsidiaries	197.6	—	—	(197.6)	—
Net income (loss)	42.4	160.5	53.3	(197.6)	58.6
Net income attributable to non-controlling partner	—	—	16.2	—	16.2
Net income (loss) attributable to Crestwood Midstream Partners LP	$42.4	$ 160.5	$ 37.1	$ (197.6)	$ 42.4

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Crestwood Midstream Partners LP
Condensed Consolidating Statements of Operations
Year Ended December 31, 2017
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 3,880.9	$ —	$ —	$ 3,880.9
Costs of product/services sold	—	3,374.7	—	—	3,374.7
Operating expenses and other:					
Operations and maintenance	—	136.0	—	—	136.0
General and administrative	67.6	25.5	—	—	93.1
Depreciation, amortization and accretion	—	202.7	—	—	202.7
Loss on long-lived assets, net	—	65.6	—	—	65.6
Goodwill impairment	—	38.8	—	—	38.8
Loss on contingent consideration	—	—	57.0	—	57.0
	67.6	468.6	57.0	—	593.2
Operating income (loss)	(67.6)	37.6	(57.0)	—	(87.0)
Earnings from unconsolidated affiliates, net	—	—	47.8	—	47.8
Interest and debt expense, net	(99.4)	—	—	—	(99.4)
Loss on modification/extinguishment of debt	(37.7)	—	—	—	(37.7)
Other income, net	—	0.8	—	—	0.8
Equity in net income (loss) of subsidiaries	3.9	—	—	(3.9)	—
Net income (loss)	(200.8)	38.4	(9.2)	(3.9)	(175.5)
Net income attributable to non-controlling partner	—	—	25.3	—	25.3
Net income (loss) attributable to Crestwood Midstream Partners LP	$(200.8)	$ 38.4	$ (34.5)	$ (3.9)	$ (200.8)

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Crestwood Midstream Partners
Condensed Consolidating Statements of Operations
Year Ended December 31, 2016
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 2,520.5	$ —	$ —	$ 2,520.5
Costs of product/services sold	—	1,925.1	—	—	1,925.1
Operating expenses and other:					
Operations and maintenance	—	155.0	—	—	155.0
General and administrative	66.4	19.2	—	—	85.6
Depreciation, amortization and accretion	—	240.5	—	—	240.5
Loss on long-lived assets, net	—	65.6	—	—	65.6
Goodwill impairment	—	162.6	—	—	162.6
	66.4	642.9	—	—	709.3
Operating loss	(66.4)	(47.5)	—	—	(113.9)
Earnings from unconsolidated affiliates, net	—	—	31.5	—	31.5
Interest and debt expense, net	(125.1)	—	—	—	(125.1)
Gain on modification/extinguishment of debt	10.0	—	—	—	10.0
Equity in net income (loss) of subsidiaries	(40.2)	—	—	40.2	—
Net income (loss)	(221.7)	(47.5)	31.5	40.2	(197.5)
Net income attributable to non-controlling partner	—	—	24.2	—	24.2
Net income (loss) attributable to Crestwood Midstream Partners LP	$(221.7)	$ (47.5)	$ 7.3	$ 40.2	$ (221.7)

Crestwood Midstream Partners LP
Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:	$(131.7)	$ 339.2	$ 53.0	$ —	$ 260.5
Cash flows from investing activities:					
Purchases of property, plant and equipment	—	(305.5)	—	—	(305.5)
Investment in unconsolidated affiliates	—	—	(64.4)	—	(64.4)
Capital distributions from unconsolidated affiliates	—	—	49.2	—	49.2
Net proceeds from sale of assets	—	79.5	—	—	79.5
Capital distributions from consolidated affiliates	27.9	—	—	(27.9)	—
Net cash provided by (used in) investing activities	27.9	(226.0)	(15.2)	(27.9)	(241.2)
Cash flows from financing activities:					
Proceeds from the issuance of long-term debt	2,274.8	—	—	—	2,274.8
Payments on long-term debt	(2,014.8)	(0.9)	—	—	(2,015.7)
Payments on capital leases	—	(1.6)	—	—	(1.6)
Payments for debt-related deferred costs	(5.7)	—	—	—	(5.7)
Distributions to partners	(238.4)	—	(9.9)	—	(248.3)
Distributions to parent	—	—	(27.9)	27.9	—
Taxes paid for unit-based compensation vesting	—	(7.4)	—	—	(7.4)
Change in intercompany balances	103.4	(103.4)	—	—	—
Other	—	0.1	—	—	0.1
Net cash provided by (used in) financing activities	119.3	(113.2)	(37.8)	27.9	(3.8)
Net change in cash and restricted cash	15.5	—	—	—	15.5
Cash and restricted cash at beginning of period	1.0	—	—	—	1.0
Cash and restricted cash at end of period	$16.5	$ —	$ —	$ —	$ 16.5

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Crestwood Midstream Partners LP
Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2017
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:	$(162.3)	$ 379.2	$ 45.3	$ —	$ 262.2
Cash flows from investing activities:					
Purchases of property, plant and equipment	—	(188.4)	—	—	(188.4)
Investment in unconsolidated affiliates	—	—	(58.0)	—	(58.0)
Capital distributions from unconsolidated affiliates	—	—	59.9	—	59.9
Net proceeds from sale of assets	—	225.2	—	—	225.2
Capital distributions from consolidated affiliates	4.3	—	—	(4.3)	—
Net cash provided by (used in) investing activities	4.3	36.8	1.9	(4.3)	38.7
Cash flows from financing activities:					
Proceeds from the issuance of long-term debt	2,838.6	—	—	—	2,838.6
Payments on long-term debt	(2,912.6)	(1.3)	—	—	(2,913.9)
Payments on capital leases	—	(2.7)	—	—	(2.7)
Payments for deferred financing costs	(1.0)	—	—	—	(1.0)
Redemption of non-controlling interest	—	—	(202.7)	—	(202.7)
Net proceeds from issuance of non-controlling interest	—	—	175.0	—	175.0
Distributions to partners	(174.0)	—	(15.2)	—	(189.2)
Distributions to parent	—	—	(4.3)	4.3	—
Taxes paid for unit-based compensation vesting	—	(5.5)	—	—	(5.5)
Change in intercompany balances	406.7	(406.7)	—	—	—
Other	—	0.2	—	—	0.2
Net cash provided by (used in) financing activities	157.7	(416.0)	(47.2)	4.3	(301.2)
Net change in cash and restricted cash	(0.3)	—	—	—	(0.3)
Cash and restricted cash at beginning of period	1.3	—	—	—	1.3
Cash and restricted cash at end of period	$1.0	$ —	$ —	$ —	$ 1.0

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Crestwood Midstream Partners LP
Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2016
(in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:	$(188.0)	$ 502.8	$ 39.0	$ —	$ 353.8
Cash flows from investing activities:					
Acquisitions, net of cash acquired	—	(7.2)	—	—	(7.2)
Purchases of property, plant and equipment	—	(100.7)	—	—	(100.7)
Investment in unconsolidated affiliates	—	—	(12.4)	—	(12.4)
Capital distributions from unconsolidated affiliates	—	—	14.8	—	14.8
Net proceeds from sale of assets	—	972.7	—	—	972.7
Capital contributions to consolidated affiliates	26.2	—	—	(26.2)	—
Net cash provided by (used in) investing activities	26.2	864.8	2.4	(26.2)	867.2
Cash flows from financing activities:					
Proceeds from the issuance of long-term debt	1,565.3	—	—	—	1,565.3
Payments on long-term debt	(2,535.3)	(0.8)	—	—	(2,536.1)
Payments on capital leases	—	(1.9)	—	—	(1.9)
Payments for deferred financing costs	(3.5)	—	—	—	(3.5)
Distributions to partners	(227.6)	—	(15.2)	—	(242.8)
Distributions to parent	—	—	(26.2)	26.2	—
Taxes paid for unit-based compensation vesting	—	(0.8)	—	—	(0.8)
Change in intercompany balances	1,364.1	(1,364.1)	—	—	—
Net cash provided by (used in) financing activities	163.0	(1,367.6)	(41.4)	26.2	(1,219.8)
Net change in cash and restricted cash	1.2	—	—	—	1.2
Cash and restricted cash at beginning of period	0.1	—	—	—	0.1
Cash and restricted cash at end of period	$1.3	$ —	$ —	$ —	$ 1.3

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Supplemental Selected Quarterly Financial Information (Unaudited)

Summarized unaudited quarterly financial data is presented below (in millions, except per unit information):

Crestwood Equity	Quarter Ended			
	March 31	June 30	September 30	December 31
2018				
Revenues	$1,115.0	$840.5	$ 930.2	$768.4
Operating income (loss)(1)	46.0	(9.1)	4.8	71.8
Loss on modification/extinguishment of debt	—	—	—	(0.9)
Earnings from unconsolidated affiliates, net	12.4	12.0	15.1	13.8
Net income (loss)	34.1	(21.5)	(5.2)	59.6
Net income (loss) attributable to partners	15.1	(40.6)	(24.3)	40.5
Net income (loss) per limited partner unit:				
Basic and Diluted	$0.21	$(0.57)	$ (0.34)	$0.57
2017				
Revenues	$828.1	$850.3	$ 955.6	$1,246.9
Operating income (loss)(2)	36.1	15.1	(15.3)	(115.3)
Loss on modification/extinguishment of debt	(37.3)	(0.4)	—	—
Earnings from unconsolidated affiliates, net	8.1	9.6	11.5	18.6
Net income (loss)	(19.4)	0.3	(27.9)	(119.6)
Net loss attributable to partners	(43.3)	(19.5)	(50.5)	(141.1)
Net loss per limited partner unit:				
Basic and Diluted	$(0.62)	$(0.28)	$ (0.72)	$(2.01)

Crestwood Midstream	Quarter Ended			
	March 31	June 30	September 30	December 31
2018				
Revenues	$1,115.0	$840.5	$ 930.2	$768.4
Operating income (loss)(1)	44.4	(11.1)	2.2	69.9
Loss on modification/extinguishment of debt	—	—	—	(0.9)
Earnings from unconsolidated affiliates, net	12.4	12.0	15.1	13.8
Net income (loss)	32.4	(23.5)	(7.8)	57.5
Net income (loss) attributable to partner	28.4	(27.5)	(11.9)	53.4
2017				
Revenues	$828.1	$850.3	$ 955.6	$1,246.9
Operating income (loss)(2)	34.2	13.0	(17.0)	(117.2)
Loss on modification/extinguishment of debt	(37.3)	(0.4)	—	—
Earnings from unconsolidated affiliates, net	8.1	9.6	11.5	18.6
Net loss	(21.4)	(1.9)	(29.8)	(122.4)
Net loss attributable to partner	(27.5)	(8.2)	(36.2)	(128.9)

(1) Amount for the three months ended June 30, 2018 and September 30, 2018 includes a loss on long-lived assets of $24.5 million and $2.4 million related to the sale of our West Coast facilities.

(2) Amount includes goodwill, property, plant and equipment and intangible asset impairments of $121.0 million during the three months ended December 31, 2017. See Note 2 for a further discussion of our impairments recorded during 2017. Amount for the three months ended December 31, 2017 includes a gain on long-lived assets of approximately $33.6 million on the sale of our 100% interest in US Salt. See Note 3 for further discussion of the sale. During the three months ended December 31, 2017, we recorded a $57 million loss on contingent

consideration related to our Stagecoach Gas equity investment. See Note 6 for a further discussion of the loss on contingent consideration.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CRESTWOOD EQUITY PARTNERS LP

By Crestwood Equity GP, LLC
(its general partner)

CRESTWOOD MIDSTREAM PARTNERS LP

By Crestwood Midstream GP LLC
(its general partner)

Dated: February 22, 2019 By /s/ ROBERT G. PHILLIPS
Robert G. Phillips
President, Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following officers of Crestwood Equity GP, LLC, as general partner of Crestwood Equity Partners LP, and Crestwood Midstream GP LLC, as general partner of Crestwood Midstream Partners LP, and the following directors of Crestwood Equity GP LLC in the capacities and on the dates indicated.

Date	Signature and Title
February 22, 2019	/s/ ROBERT G. PHILLIPS Robert G. Phillips, President, Chief Executive Officer and Director (Principal Executive Officer)
February 22, 2019	/s/ ROBERT T. HALPIN Robert T. Halpin, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
February 22, 2019	/s/ STEVEN M. DOUGHERTY Steven M. Dougherty, Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
February 22, 2019	/s/ ALVIN BLEDSOE Alvin Bledsoe, Director
February 22, 2019	/s/ GARY D. REAVES Gary D. Reaves, Director
February 22, 2019	/s/ WARREN H. GFELLER Warren H. Gfeller, Director

February 22, 2019	/s/ JANEEN S. JUDAH Janeen S. Judah, Director
February 22, 2019	/s/ DAVID LUMPKINS David Lumpkins, Director
February 22, 2019	/s/ JOHN J. SHERMAN John J. Sherman, Director
February 22, 2019	/s/ JOHN W. SOMERHALDER II John W. Somerhalder II, Director

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Schedule I

Crestwood Equity Partners LP
Parent Only
Condensed Balance Sheets
(in millions)

	December 31,	
	2018	2017
Assets		
Current assets:		
Cash	$0.2	$0.3
Total current assets	0.2	0.3
Property, plant and equipment, net	1.1	1.2
Intangible assets, net	—	1.4
Investments in subsidiaries	1,854.7	2,005.1
Other assets	2.8	3.5
Total assets	$1,858.8	$2,011.5
Liabilities and partners’ capital		
Current liabilities:		
Accounts payable	$2.6	$2.7
Accrued expenses	1.1	1.2
Total current liabilities	3.7	3.9
Other long-term liabilities	2.6	2.1
Total partners’ capital	1,852.5	2,005.5
Total liabilities and partners’ capital	$1,858.8	$2,011.5

See accompanying notes.

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Schedule I

Crestwood Equity Partners LP
Parent Only
Condensed Statements of Operations
(in millions)

	Year Ended December 31,		
	2018	2017	2016
Revenues	$—	$—	$—
Expenses	6.1	6.7	6.0
Operating loss	(6.1)	(6.7)	(6.0)
Equity in net income (loss) of subsidiaries	72.7	(160.4)	(186.6)
Other income, net	0.4	0.5	0.5
Net income (loss)	67.0	(166.6)	(192.1)
Net income attributable to non-controlling partners	16.2	25.3	24.2
Net income (loss) attributable to Crestwood Equity Partners LP	$50.8	$(191.9)	$(216.3)

See accompanying notes.

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Schedule I

Crestwood Equity Partners LP
Parent Only
Condensed Statements of Comprehensive Income
(in millions)

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$67.0	$(166.6)	$(192.1)
Change in fair value of Suburban Propane Partners, LP units	(0.7)	(0.8)	0.8
Comprehensive income (loss)	66.3	(167.4)	(191.3)
Comprehensive income attributable to non-controlling interest	16.2	25.3	24.2
Comprehensive income (loss) attributable to Crestwood Equity Partners LP	$50.1	$(192.7)	$(215.5)

See accompanying notes.

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Schedule I

Crestwood Equity Partners LP
Parent Only
Condensed Statements of Cash Flows
(in millions)

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities	$(3.8)	$(3.6)	$(3.5)
Cash flows from investing activities	238.4	174.0	227.6
Cash flows from financing activities:			
Principal payments on long-term debt	—	—	(0.2)
Distributions paid to partners	(230.9)	(182.6)	(219.8)
Proceeds from issuance of common units	—	15.2	—
Change in intercompany balances	(3.8)	(3.0)	(4.2)
Net cash used in financing activities	(234.7)	(170.4)	(224.2)
Net change in cash	(0.1)	—	(0.1)
Cash at beginning of period	0.3	0.3	0.4
Cash at end of period	$0.2	$0.3	$0.3

See accompanying notes.

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Schedule I

Crestwood Equity Partners LP
Parent Only
Notes to Condensed Financial Statements

Note 1. Basis of Presentation

In the parent-only financial statements, our investment in subsidiaries is stated at cost plus equity in undistributed earnings of subsidiaries since the date of acquisition. Our share of net income of our unconsolidated subsidiaries is included in consolidated income using the equity method. The parent-only financial statements should be read in conjunction with our consolidated financial statements.

Note 2. Distributions

During the years ended December 31, 2018, 2017 and 2016, we received cash distributions from Crestwood Midstream Partners LP of approximately $238.4 million, $174.0 million and $227.6 million.

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Schedule II

Crestwood Equity Partners LP
Crestwood Midstream Partners LP
Valuation and Qualifying Accounts
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Balance at beginning of period	Charged to costs and expenses	Other Additions	Deductions (write-offs)	Balance at end of period
Allowance for doubtful accounts					
2018	$ 2.4	$ 0.2	$ —	$ (2.3)	$ 0.3
2017	1.9	1.5	—	(1.0)	2.4
2016	0.4	1.9	—	(0.4)	1.9