Summit Midstream Partners, LP
Form 10-K
February 26, 2019
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smlp:DropDownAssets2016AcquisitionMember us-gaap:SubsequentEventMember 2019-02-25 2019-02-26
0001549922 smlp:SummitMidstreamPartnersHoldingsLLCMember smlp:DropDownAssets2016AcquisitionMember
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smlp:DropDownAssets2016AcquisitionMember us-gaap:ScenarioForecastMember 2020-06-30 0001549922
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2018-12-31 0001549922 us-gaap:GeneralPartnerMember smlp:SummitMidstreamPartnersHoldingsLLCMember

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smlp:TiogaMidstreamLLCMember 2019-02-25 2019-02-26 0001549922
smlp:SummitMidstreamPartnersHoldingsLLCMember us-gaap:SubsequentEventMember
us-gaap:LimitedPartnerMember smlp:SummitMidstreamPartnersLPMember 2019-02-25 2019-02-26 0001549922
smlp:EnergyCapitalPartnersMember us-gaap:SubsequentEventMember us-gaap:LimitedPartnerMember
smlp:SummitMidstreamPartnersLPMember 2019-02-25 2019-02-26
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

Commission file number: 001-35666

Summit Midstream Partners, LP

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware | 45-5200503 |
| (State or other jurisdiction of<br><br>incorporation or organization) | (I.R.S. Employer<br><br>Identification No.) |
| 1790 Hughes Landing Blvd, Suite 500<br><br>The Woodlands, TX | 77380 |
| (Address of principal executive offices) | (Zip Code) |

Registrant’s telephone number, including area code: (832) 413-4770

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

| Title of each class | Name of exchange on which registered |
|---|---|
| Common Units | New York Stock Exchange |

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

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

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

Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer

Non-accelerated filer 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.

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

The aggregate market value of the common units held by non-affiliates of the registrant as of June 30, 2018, was $633,243,457.

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date: The registrant had 73,462,254 common units and 1,490,999 general partner units outstanding at February 13, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

None

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ORGANIZATIONAL CHART

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COMMONLY USED OR DEFINED TERMS

| | |
|---|---|
| 2014 SRS | the Partnership's shelf registration statement initially filed with the SEC in July 2014 and amended in February 2017 which registered an indeterminate amount of common units, debt securities and guarantees (superseded by the 2017 SRS) |
| 2016 Drop Down | the Partnership's March 3, 2016 acquisition from SMP Holdings of substantially all of (i) the issued and outstanding membership interests in Summit Utica, Meadowlark Midstream and Tioga Midstream and (ii) SMP Holdings' 40% ownership interest in Ohio Gathering |
| 2016 SRS | the Partnership's shelf registration statement declared effective in November 2016 which registered up to $1.5 billion of equity and debt securities in primary offerings and 36,701,230 common units beneficially owned by Summit Investments and affiliates of the Sponsor |
| 2017 SRS | the Partnership's automatic shelf registration statement of well-known seasoned issuers filed with the SEC in July 2017 which registered an indeterminate amount of common units, preferred units, debt securities and guarantees and subsequently amended in November 2017 |
| 5.5% Senior Notes | Summit Holdings' and Finance Corp.'s 5.5% senior unsecured notes due August 2022 |
| 7.5% Senior Notes | Summit Holdings' and Finance Corp.'s 7.5% senior unsecured notes redeemed in March 2017 |
| 5.75% Senior Notes | Summit Holdings' and Finance Corp.'s 5.75% senior unsecured notes due April 2025 |
| AMI | area of mutual interest; AMIs require that any production from wells drilled by our customers within the AMI be shipped on and/or processed by our gathering systems |
| associated natural gas | a form of natural gas which is found with deposits of petroleum, either dissolved in the crude oil or as a free gas cap above the crude oil in the reservoir |
| ASU | Accounting Standards Update |
| Audit Committee | the audit committee of the board of directors of our General Partner |
| Bbl | one barrel; used for crude oil and produced water and equivalent to 42 U.S. gallons |
| Bcf | one billion cubic feet |

| | |
|---|---|
| Bcfe/d | the equivalent of one billion cubic feet per day; generally calculated when liquids are converted into natural gas; determined using a ratio of six thousand cubic feet of natural gas to one barrel of liquids |
| Bison Midstream | Bison Midstream, LLC |
| Board of Directors | the board of directors of our General Partner |
| CAA | Clean Air Act |
| CEA | Commodity Exchange Act |
| CERCLA | Comprehensive Environmental Response, Compensation and Liability Act |
| CFTC | Commodity Futures Trading Commission |
| Compensation Committee | the compensation committee of the board of directors of our General Partner |
| Compensation Consultant | BDO USA, L.L.P. |
| condensate | a natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions |
| Conflicts Committee | the conflicts committee of the board of directors of our General Partner |
| CWA | Clean Water Act |
| Deferred Purchase Price Obligation | the deferred payment liability recognized in connection with the 2016 Drop Down; also referred to as DPPO |
| DFW Midstream | DFW Midstream Services LLC |
| DJ Basin | Denver-Julesburg Basin |
| Dodd-Frank Act | Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 |
| DOT | U.S. Department of Transportation |
| dry gas | natural gas primarily composed of methane where heavy hydrocarbons and water either do not exist or have been removed through processing or treating |
| Energy Capital Partners | Energy Capital Partners II, LLC and its parallel and co-investment funds; also known as the Sponsor |

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| EPA | Environmental Protection Agency |
| Epping | Epping Transmission Company, LLC |
| EPU | earnings or loss per unit |
| Exchange Act | Securities Exchange Act of 1934, as amended |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Finance Corp. | Summit Midstream Finance Corp. |
| FTC | Federal Trade Commission |
| GAAP | accounting principles generally accepted in the United States of America |
| General Partner | Summit Midstream GP, LLC |
| GHG | greenhouse gas(es) |
| Grand River | Grand River Gathering, LLC |
| hub | geographic location of a storage facility and multiple pipeline interconnections |
| ICA | Interstate Commerce Act |
| IDR | incentive distribution rights |
| IPO | initial public offering |
| IRS | Internal Revenue Service |
| LIBOR | London Interbank Offered Rate |
| Mbbl/d | one thousand barrels per day |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations |
| Meadowlark Midstream | Meadowlark Midstream Company, LLC |
| MMBtu | one million British Thermal Units |
| MMcf/d | one million cubic feet per day |
| Mountaineer Midstream | Mountaineer Midstream gathering system |
| MQD | minimum quarterly distribution |
| MVC | minimum volume commitment |
| NAAQS | national ambient air quality standard |
| NEPA | National Environmental Policy Act |
| NGA | Natural Gas Act |
| NGLs | natural gas liquids; the combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from unprocessed natural gas streams become liquid under various levels of higher pressure and lower temperature |
| NGPA | Natural Gas Policy Act of 1978 |
| Niobrara G&P | Niobrara Gathering and Processing system |
| NYSE | New York Stock Exchange |
| OCC | Ohio Condensate Company, L.L.C. |
| OGC | Ohio Gathering Company, L.L.C. |
| Ohio Gathering | Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. |
| OPA | Oil Pollution Control Act |
| OpCo | Summit Midstream OpCo, LP |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| play | a proven geological formation that contains commercial amounts of hydrocarbons |
| Permian Finance | Summit Midstream Permian Finance, LLC |

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| Polar and Divide | the Polar and Divide system; collectively Polar Midstream and Epping |
| Polar Midstream | Polar Midstream, LLC |
| produced water | water from underground geologic formations that is a by-product of natural gas and crude oil production |
| PSD | Prevention of Significant Deterioration |
| RCRA | Resource Conservation and Recovery Act |
| Red Rock Gathering | Red Rock Gathering Company, LLC |
| Remaining Consideration | management's estimate of the consideration to be paid to SMP Holdings in 2020 in connection with the 2016 Drop Down, the present value of which is reflected on our balance sheets as the Deferred Purchase Price Obligation |
| Revolving Credit Facility | the Third Amended and Restated Credit Agreement dated as of May 26, 2017, as amended by the First Amendment to Third Amended and Restated Credit Agreement dated as of September 22, 2017 |
| SEC | Securities and Exchange Commission |

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| Securities Act | Securities Act of 1933, as amended |
| segment adjusted EBITDA | total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) our proportional adjusted EBITDA for equity method investees, (iii) depreciation and amortization, (iv) adjustments related to MVC shortfall payments, (v) adjustments related to capital reimbursement activity, (vi) unit-based and noncash compensation, (vii) the change in the Deferred Purchase Price Obligation fair value, (viii) early extinguishment of debt expense, (ix) impairments and (x) other noncash expenses or losses, less other noncash income or gains |
| shortfall payment | the payment received from a counterparty when its volume throughput does not meet its MVC for the applicable period |
| SMLP | Summit Midstream Partners, LP |
| SMLP LTIP | SMLP Long-Term Incentive Plan |
| SMP Holdings | Summit Midstream Partners Holdings, LLC |
| SPCC | Spill Prevention Control and Countermeasure |
| Sponsor | Energy Capital Partners II, LLC and its parallel and co-investment funds; also known as Energy Capital Partners |
| Summit Holdings | Summit Midstream Holdings, LLC |
| Summit Investments | Summit Midstream Partners, LLC |
| Summit Niobrara | Summit Midstream Niobrara, LLC |
| Summit Marketing | Summit Midstream Marketing, LLC |
| Summit Permian | Summit Midstream Permian, LLC |
| Summit Permian II | Summit Midstream Permian II, LLC |
| Summit Permian Transmission | Summit Permian Transmission, LLC |
| Summit Utica | Summit Midstream Utica, LLC |
| Tcfe | the equivalent of one trillion cubic feet |
| the Company | Summit Midstream Partners, LLC and its subsidiaries |
| the Partnership | Summit Midstream Partners, LP and its subsidiaries |
| throughput volume | the volume of natural gas, crude oil or produced water gathered, transported or passing through a pipeline, plant or other facility during a particular period; also referred to as volume throughput |
| Tioga Midstream | Tioga Midstream, LLC |
| unconventional resource | a basin where natural gas or crude oil production is developed from unconventional |

| | |
|---|---|
| basin | sources that require hydraulic fracturing as part of the completion process, for instance, natural gas produced from shale formations and coalbeds; also referred to as an unconventional resource play |
| VOC | volatile organic compound(s) |
| wellhead | the equipment at the surface of a well, used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground |

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PART I

Item 1. Business.

SMLP is a Delaware limited partnership. References to "we" or "our" refer collectively to SMLP and its subsidiaries. For additional information, see Note 1 to the consolidated financial statements.

Item 1. Business is divided into the following sections:



Overview

We are a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in the continental United States. Our systems gather natural gas from pad sites, wells and central receipt points connected to our systems. Gathered natural gas volumes are then compressed, dehydrated, treated and/or processed for delivery to downstream pipelines serving processing plants and/or end users. We also contract with producers to gather crude oil and produced water from wells connected to our systems for delivery to downstream pipelines and third-party rail terminals in the case of crude oil and to third-party disposal wells in the case of produced water. We generally refer to all of the services our systems provide as gathering services.

We classify our midstream energy infrastructure assets into two categories:

- Core Focus Areas – production basins in which we expect our gathering systems to experience greater long-term growth, driven by our customers' ability to generate more favorable returns and support sustained drilling and completion activity in varying commodity price environments. In the near-term, we expect to concentrate the majority of our capital expenditures in our Core Focus Areas. Our Utica Shale, Ohio Gathering, Williston Basin, DJ Basin and Permian Basin reportable segments (as described below) comprise our Core Focus Areas.
- Legacy Areas – production basins in which we expect our gathering systems to experience relatively lower long-term growth compared to our Core Focus Areas, given that our customers require relatively higher commodity prices to support drilling and completion activities in these basins. Upstream production served by our gathering systems in our Legacy Areas is generally more mature, as compared to our Core Focus Areas, and the decline rates for volume throughput on our gathering systems in the Legacy Areas are typically lower as a result. We expect to continue to moderate our near-term capital expenditures in these Legacy Areas. Our Piceance Basin, Barnett Shale and Marcellus Shale reportable segments (as described below) comprise our Legacy Areas.

We are the owner-operator of, or have significant ownership interests in, the following gathering systems, which comprise our Core Focus Areas:

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;

- Ohio Gathering, a natural gas gathering system and a condensate stabilization facility operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;

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- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Tioga Midstream, a crude oil, produced water and associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota (we have entered into agreements for the sale of Tioga Midstream, as discussed below);
- Bison Midstream, an associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Niobrara G&P, an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara and Codell shale formations in northeastern Colorado; and
- Summit Permian, an associated natural gas gathering and processing system in the northern Delaware Basin, which includes the Bone Spring and Wolfcamp formations, in southeastern New Mexico.

We are the owner-operator of the following gathering systems, which comprise our Legacy Areas:

- Grand River, a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah;
- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia.

The systems that we operate and/or have significant ownership interests in have a diverse group of customers and counterparties comprising affiliates and/or subsidiaries of some of the largest natural gas and crude oil producers in North America.

Key customers in our Core Focus Areas are as follows:

- Utica Shale – XTO Energy Inc. ("XTO") and Ascent Resources - Utica, LLC ("Ascent") are the key customers for Summit Utica.
- Ohio Gathering – Ascent and Gulfport Energy Corporation ("Gulfport") are the key customers for Ohio Gathering;
- Williston Basin – Whiting Petroleum Corp. ("Whiting") and Zavanna, LLC (“Zavanna”) are the key customers for Polar and Divide. Oasis Petroleum, Inc. ("Oasis") and a large U.S. independent crude oil and natural gas company, are the key customers for Bison Midstream. Hess Corp. (“Hess”) is the key customer for Tioga Midstream.
- DJ Basin – HighPoint Resources Corporation ("HighPoint") and a large U.S. independent crude oil and natural gas company are the key customers for Niobrara G&P.
- Permian Basin – XTO is the key customer for Summit Permian.

We believe that our gathering systems in the Core Focus Areas are positioned for long-term growth through further development by our customers and increased utilization of our gathering systems. We intend to continue expanding our operations and creating additional scale in our Core Focus Areas through the execution of new, and the expansion of existing, strategic partnerships with our existing and prospective customers.

Key customers in our Legacy Areas are as follows:

- Piceance Basin – Caerus Oil & Gas LLC ("Caerus") and Terra Energy Partners LLC ("Terra") are the key customers for Grand River.
- Barnett Shale – Total Gas & Power North America, Inc. ("Total") is the key customer for DFW Midstream.

- Marcellus Shale – Antero Resources Corp. ("Antero") is the key customer for Mountaineer Midstream.

We believe that our customers in our Legacy Areas will pursue a slower pace of drilling and completion activity than customers in our Core Focus Areas. As a result, volume throughput in our Legacy Areas could experience a lower rate of growth than our gathering systems in our Core Focus Areas or volume declines. In general, our gathering systems in our Legacy Areas have larger and longer-lived MVCs and experience lower volume throughput decline rates as compared to our gathering systems in our Core Focus Areas. We may also consider divestitures of certain of our lower growth gathering systems included in our Core Focus Areas or our Legacy Areas, which could result in a reallocation of capital or other resources to our Core Focus Areas. For example, in February 2019, SMLP announced that it had executed definitive agreements with Hess Infrastructure Partners LP and one of its affiliates (collectively, “Hess Infrastructure”) related to the sale of Tioga Midstream for cash consideration of $90 million, subject to adjustment.

Our financial results are primarily driven by volume throughput across our gathering systems and by expense management. During 2018, aggregate natural gas volume throughput averaged 1,673 MMcf/d and crude oil and produced water volume throughput averaged 94.9 Mbbl/d. A majority of the volumes that we gather, treat and/or process have a fixed-fee rate structure which enhances the stability of our cash flows by providing a revenue stream that is not directly subject to fluctuations in commodity prices. Activities that expose us directly to commodity prices include (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River systems, (ii) natural gas and crude oil marketing services in and around our gathering systems, (iii) the sale of natural gas we retain from certain DFW Midstream customers and (iv) the sale of condensate we retain from our gathering services at Grand River. These additional activities, including marketing transactions comprised of buy and sell arrangements, directly expose us to fluctuations in commodity prices and accounted for approximately 27% of total revenues during the year ended December 31, 2018. These additional activities, excluding marketing transactions comprised of buy and sell arrangements, accounted for approximately 11% of total revenues during the year ended December 31, 2018.

In addition, the vast majority of our gathering and/or processing agreements in both our Core Focus Areas and our Legacy Areas include AMIs. Our AMIs cover approximately 3.3 million surface acres in the aggregate, which includes more than 0.8 million surface acres associated with Ohio Gathering. Certain of our gathering and processing agreements also include MVCs. To the extent the customer does not meet its MVC, it must make an MVC shortfall payment to cover the shortfall of required volume throughput not shipped or processed, either on a monthly, annual or multi-year basis. We have designed our MVC provisions to ensure that we will generate a certain amount of revenue from each customer over the life of the associated gathering and/or processing agreement, whether by collecting gathering or processing fees on actual throughput or from cash payments to cover any MVC shortfall. As of December 31, 2018, we had remaining MVCs totaling 2.2 Tcfe. Our MVCs have a weighted-average remaining life of 6.4 years (assuming contracted minimum volume commitments for the remainder of the term) and average approximately 1.0 Bcfe/d through 2023.

We use a variety of financial and operational metrics to analyze our performance, including among others, throughput volume, revenues, operation and maintenance expenses and segment adjusted EBITDA. We view each of these operational and/or GAAP metrics as important factors in evaluating our profitability and determining the amount of cash distributions we pay to our unitholders.

For additional information on our results of operations, see Item 6. Selected Financial Data and the "Results of Operations" section included in the Item 7. MD&A.

Our Sponsor and Summit Investments.  Energy Capital Partners, together with its affiliated funds, is a private equity firm with over $19.0 billion in capital commitments that is focused on investing in North America's energy infrastructure. Energy Capital Partners has significant energy and financial expertise to complement its investment in us, including investments in the power generation, midstream oil and gas, electric transmission, energy equipment and services, environmental infrastructure and other energy-related sectors.

Summit Investments, which was formed in 2009 by members of our management team and our Sponsor, is the ultimate owner of our General Partner. We are managed and operated by the Board of Directors and executive officers of our General Partner, which is managed and operated by Summit Investments. As a result, due to its ownership interest in Summit Investments and its representation on Summit Investments' board of managers, Energy Capital Partners controls our General Partner and its activities, thereby controlling SMLP.

Recent Developments

On February 26, 2019, we announced our execution of the following agreements:

- Purchase and sale agreements with Hess Infrastructure pursuant to which SMLP agreed to sell Tioga Midstream for $90 million, subject to adjustment (“Tioga PSAs”).
- An amendment to the Contribution Agreement (the “Amendment”) related to the 2016 Drop Down pursuant to which the Partnership shall make a cash payment of $100 million to SMP Holdings. Following the closing of the Amendment, the Remaining Consideration will be fixed at $303.5 million, and will be payable by the Partnership in one or more payments over the period from March 1, 2020 through December 31, 2020, payable in (i) cash, (ii) the Partnership’s common units or (iii) a combination of cash and the Partnership’s common units, at the discretion of the Partnership. No less than 50% of the Remaining Consideration shall be paid on or before June 30, 2020 and interest shall accrue at a rate of 8% per annum on any portion of the Remaining Consideration that remains unpaid after March 31, 2020.
- An equity restructuring agreement with the General Partner and SMP Holdings (the “Equity Restructuring Agreement”) pursuant to which the IDRs and the 2% general partner interest held by the General Partner will be converted into 8,750,000 common units and a non-economic general partner interest (the “Equity Restructuring”and collectively with the Tioga PSAs and the Amendment, the “February 2019 Transactions”).

The February 2019 Transactions are expected to close before the end of the first quarter of 2019, subject to customary closing conditions. Immediately following the closing of the Equity Restructuring Agreement, SMP Holdings will directly own a 42.1% limited partner interest in SMLP and an affiliate of Energy Capital Partners II, LLC will directly own a 7.2% limited partner interest in SMLP. In connection with the February 2019 Transactions, the Partnership announced that it expects to reduce its common unit distribution to $0.2875 per quarter, beginning with the distribution to be paid in respect of the first quarter of 2019.

Business Strategies

Our key business strategies are as follows:

- ***Maintaining our focus on fee-based revenue with minimal direct commodity price exposure.*** We intend to maintain our focus on providing midstream energy services under primarily long-term and fee-based contracts. We believe that our focus on fee-based revenues with minimal direct commodity price exposure is essential to maintaining stable cash flows.
- ***Enhancing our asset base by expanding our midstream service offerings in our Core Focus Areas.*** The systems that comprise our Core Focus Areas are located in production basins that we believe enable our customers to generate more favorable upstream returns and support sustained drilling and completion activity in varying commodity price environments. In some cases, production from our customers in these Core Focus Areas is expected to grow in excess of our existing throughput capacity over time, which will create opportunities for additional midstream infrastructure development. We intend to leverage our management team's expertise in constructing, developing and optimizing our midstream assets to enhance our operating footprint and increase our scale in our Core Focus Areas.

- ***Maintaining strong producer relationships to maximize utilization of all of our midstream assets.*** We have cultivated strong producer relationships by focusing on customer service, reliable project execution and by operating our assets safely and reliably over time. We believe that our strong producer relationships will create future opportunities to optimize the utilization of the gathering systems in our Legacy Areas and develop new midstream energy infrastructure in our Core Focus Areas.

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- ***Allocating capital to maximize unitholder value.*** The Partnership will seek to maximize unitholder value by allocating its available capital and maintaining its commitment to risk-informed stable cash flows. This may include a re-allocation of capital into new areas, existing areas or other obligations of the Partnership, including the Deferred Purchase Price Obligation. We may execute on opportunistic divestitures as part of this strategy, which could include certain assets located in our Core Focus Areas or Legacy Areas. For example, in February 2019, SMLP announced that it had executed definitive agreements with Hess Infrastructure related to the sale of Tioga Midstream for cash consideration of $90 million, subject to adjustment.
- ***Continuing to prioritize safe and reliable operations.*** We believe that providing safe, reliable and efficient operations is a key component of our business strategy. We place a strong emphasis on employee training, operational procedures, and enterprise technology, and we intend to continue promoting a high standard with respect to the efficiency of our operations and the safety of all of our constituents.

Our Midstream Assets

Our midstream assets, including assets in which we have a significant ownership interest, currently operate in the following unconventional resource plays:

Core Focus Areas

- the Utica Shale, which is served by Summit Utica;
- Ohio Gathering, which operates in the Appalachian Basin and includes our ownership interests in OGC and OCC;
- the Williston Basin, which is served by Polar and Divide, Tioga Midstream and Bison Midstream;
- the DJ Basin, which is served by Niobrara G&P; and
- the Permian Basin, which is served by Summit Permian.

Legacy Areas

- the Piceance Basin, which is served by Grand River;
- the Barnett Shale, which is served by DFW Midstream; and
- the Marcellus Shale, which is served by Mountaineer Midstream.

We compete with other midstream companies, producers and intrastate and interstate pipelines. Competition for volumes is primarily based on reputation, commercial terms, service levels, access to end-use markets, geographic proximity of existing assets to a producer's acreage and available capacity. We may also face competition to gather production outside of our AMIs and attract producer volumes to our gathering systems. Additionally, we could face incremental competition to the extent we make acquisitions.

We earn revenue by providing gathering, compression, treating and/or processing services pursuant to primarily long-term and fee-based gathering and processing agreements with some of the largest and most active producers in North America. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

The significant features of our gathering and processing agreements and the gathering systems to which they relate are discussed in more detail below. For additional operating and financial performance information, on a consolidated basis and by reportable segment, see the "Results of Operations" section in Item 7. MD&A.

Areas of Mutual Interest. The vast majority of our gathering and processing agreements contain AMIs, some of which extend through 2036. The AMIs generally require that any production by our customers within the AMIs will be shipped on and/or processed by our assets. In general, our customers have not leased acreage that cover our entire

AMIs but, to the extent that they lease additional acreage within our AMIs in the future, any production from wells drilled by them within that AMI will be dedicated to our systems.

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Under certain of our gathering agreements, we have agreed to construct pipeline laterals to connect our gathering systems to producer pad sites located within the AMI. However, in certain circumstances we may choose not to fund a pad connection opportunity presented by a customer or we may choose not to fund capital calls in Ohio Gathering if we believe that the investment would not meet our internal return expectations. Under this scenario, the customer may, in certain circumstances, construct the infrastructure itself and sell it to us at a price equal to their cost plus an applicable profit margin, or, in some cases, we may release the relevant acreage dedication from the AMI. For Ohio Gathering, our joint venture partner may elect to fund 100% of the capital call, which could reduce our ownership interests in OGC and/or OCC.

Minimum Volume Commitments. Certain of our gathering and/or processing agreements contain MVCs, which, like AMIs, benefit the development and ongoing operation of a gathering system because they provide a contracted monthly, annual or multi-year minimum revenue stream. As of December 31, 2018, we had remaining MVCs totaling 2.2 Tcfe. Our MVCs had a weighted-average remaining life of 6.4 years (assuming contracted minimum volume commitments for the remainder of the term) and average approximately 1.0 Bcfe/d through 2023. In addition, certain of our customers have an aggregate MVC, which is a total amount of volume throughput that the customer has agreed to ship and/or process on our systems (or an equivalent monetary amount) over the MVC term. In these cases, once a customer achieves its aggregate MVC, any remaining future MVCs will terminate and the customer will then simply pay the applicable gathering or processing rate multiplied by the actual throughput volumes shipped or processed, pursuant to the contract. As a result of this mechanism, in many cases, the weighted-average remaining period for which our MVCs apply is less than the weighted-average of the remaining contract life.

For additional information on our MVCs, see Notes 2 and 9 to the consolidated financial statements.

Utica Shale

The following table provides operating information regarding our Utica Shale reportable segment as of December 31, 2018.

| | Aggregate throughput capacity (MMcf/d) | Average daily MVCs through 2023 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) | Weighted-average remaining MVC life (Years) |
|---|---|---|---|---|---|
| Utica Shale | 720 | n/a | n/a | 10.9 | n/a |

Summit Utica. The Summit Utica system is a natural gas gathering system located in Belmont and Monroe counties in southeastern Ohio and serves producers targeting the dry gas window of the Utica and Point Pleasant shale formations. The Summit Utica system gathers and delivers natural gas, primarily under long-term, fee-based gathering agreements, which include acreage dedications. XTO and Ascent are the key customers of Summit Utica.

We have connected a substantial number of our customers' pad sites to our gathering system and we expect to benefit in the near-term from incremental volumes arising from drilling and completion activity that is occurring and will continue to occur on previously connected pad sites. Over time, we intend to expand our midstream service offering for the Summit Utica system to connect additional customer pad sites and install centralized compression facilities. Centralized compression services have been dedicated to us in our gathering agreements and will eventually constitute a new revenue stream from our customers; however, to date, this service has not been required given the relatively high downhole pressures exhibited by dry gas wells in the Utica Shale compared to other unconventional shale plays.

The Summit Utica system interconnects with the Ohio River System pipeline, which delivers to the Clarington Hub in Clarington, Ohio.

The Summit Utica system currently provides natural gas midstream services for the Utica Shale reportable segment.

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## Ohio Gathering

Ohio Gathering. Ohio Gathering comprises a natural gas gathering system and condensate stabilization facility located in the core of the Utica Shale in southeastern Ohio. The gathering system spans the condensate, liquids-rich and dry gas windows of the Utica Shale for multiple producers that are targeting production from the Utica and Point Pleasant shale formations across Belmont, Monroe, Guernsey, Harrison and Noble counties in southeastern Ohio. Substantially all gathering services on the Ohio Gathering system are provided pursuant to long-term, fee-based gathering agreements. Ascent and Gulfport are Ohio Gathering's key customers. AMIs for Ohio Gathering total approximately 825,000 surface acres in the aggregate.

Condensate and liquids-rich natural gas production is gathered, compressed, dehydrated and delivered to the Cadiz and Seneca processing complexes, which total approximately 1.3 Bcf/d of processing capacity and are owned by a joint venture between MPLX LP (“MPLX”) and The Energy and Minerals Group. Dry gas production is gathered, dehydrated, compressed, and delivered to third-party pipelines serving the northeast and mid-west markets.

Ohio Gathering also operates one of the largest condensate stabilization facilities in Ohio. This facility serves as the origination point for MPLX’s Cornerstone Pipeline which delivers condensate to Marathon Petroleum’s refinery in Canton, Ohio.

As of December 31, 2018, we owned a 40% ownership interest in Ohio Gathering. For additional information, see Note 8 to the consolidated financial statements.

Williston Basin

The following table provides operating information regarding our Williston Basin reportable segment as of December 31, 2018.

| | Aggregate throughput capacity - liquids (Mbbl/d) | Aggregate throughput capacity - natural gas (MMcf/d) | Average daily MVCs through 2023 (MMcfe/d) (1) | Remaining MVCs (Bcfe) (1) | Weighted-average remaining contract life (Years) (1)(2) | Weighted-average remaining MVC life (Years) (1)(2) |
|---|---|---|---|---|---|---|
| Williston Basin | 300 | 46 | 78 | 143 | 4.0 | 3.2 |

(1) Contract terms related to MVCs are presented for liquids and natural gas on a combined basis.

(2) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Williston Basin reportable segment total approximately 1.3 million surface acres in the aggregate.

Polar and Divide. The Polar and Divide system, which is located primarily in Williams and Divide counties in northwestern North Dakota, owns, operates and is currently developing crude oil and produced water gathering systems and transmission pipelines serving multiple customers that are targeting crude oil production from the Bakken and Three Forks shale formations. The Polar and Divide system is underpinned by long-term, fee-based gathering agreements, which include acreage dedications. Whiting and Zavanna are the key customers of the Polar and Divide system.

Crude oil that is gathered by the Polar and Divide system is delivered to interconnects with (i) the Dakota Access Pipeline, (ii) the COLT Hub rail facility, (iii) Enbridge Inc's North Dakota Pipeline System, and (iv) Global Partners LP's Basin Transload rail terminal. Produced water is delivered to third-party disposal facilities.

The Polar and Divide system currently provides crude oil and produced water midstream services for the Williston Basin reportable segment.

Tioga Midstream. The Tioga Midstream system, which currently provides associated natural gas, crude oil and produced water midstream services for the Williston Basin reportable segment, is located in Williams County, North Dakota. Gathering services on the Tioga Midstream system are primarily provided pursuant to long-term, fee-based gathering agreements with Hess, which is primarily targeting crude oil production from the Bakken and Three Forks shale formations. The gathering agreements include an annual rate redetermination mechanism, which effectively

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serves to protect future cash flows by resetting the gathering rate upward from pre-established base gathering rates in the event that Hess under performs from certain pre-established minimum production thresholds. The annual rate redeterminations can also reset the gathering rate lower in the event that Hess exceeds the minimum production threshold.

All crude oil, produced water and natural gas gathered on the Tioga Midstream system is delivered to downstream pipelines and disposal wells (for produced water) that are owned and operated by affiliates of Hess Infrastructure Partners LP. In February 2019, SMLP announced that it had executed definitive agreements with Hess Infrastructure related to the sale of Tioga Midstream for cash consideration of $90 million, subject to adjustment.

Bison Midstream. The Bison Midstream system is located in Mountrail and Burke counties in northwestern North Dakota. Bison Midstream gathers, compresses and treats associated natural gas that exists in the crude oil stream produced from the Bakken and Three Forks shale formations. Our gathering agreements for the Bison Midstream system include long-term, fee-based or percent-of-proceeds contracts. Volume throughput on the Bison Midstream system is underpinned by acreage dedications and MVCs from its key customers. A large U.S. independent crude oil and natural gas company and Oasis are the key customers of Bison Midstream.

Natural gas gathered on the Bison Midstream system is delivered to Aux Sable Midstream LLC's (“Aux Sable”) Palermo Conditioning Plant in Palermo, North Dakota and then delivered to downstream pipelines serving Aux Sable’s 2.1 Bcf/d natural gas processing plant in Channahon, Illinois.

The Bison Midstream system currently provides associated natural gas midstream services for the Williston Basin reportable segment.

DJ Basin

The following table provides operating information regarding our DJ Basin reportable segment as of December 31, 2018.

| | Aggregate throughput capacity (MMcf/d) | Average daily MVCs through 2023 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) (1) | Weighted-average remaining MVC life (Years) (1) |
|---|---|---|---|---|---|
| DJ Basin | 20 | 10 | 19 | 8.0 | 4.6 |

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the DJ Basin reportable segment total approximately 185,000 surface acres in the aggregate.

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***Niobrara G&P.*** The Niobrara G&P system is located near Hereford, Colorado, in Weld County, the largest crude oil and natural gas producing county in the state. Gathering and processing services on the Niobrara G&P system are provided pursuant to long-term, fee-based gathering agreements with producers that are primarily targeting crude oil production from the Niobrara and Codell shale formations. HighPoint and a large U.S. independent crude oil and natural gas company are the key customers of the Niobrara G&P system and have underpinned our volume throughput with acreage dedications and MVCs.

The Niobrara G&P system operates a low-pressure associated natural gas gathering system, and a cryogenic natural gas processing plant with processing capacity of 20 MMcf/d. The Niobrara G&P system also processes liquids-rich natural gas that is produced by a customer in Laramie County, Wyoming and is delivered to the inlet of our processing plant by a third-party gathering system.

In November 2017, we announced the expansion of our existing gathering and processing complex with the addition of a new 60 MMcf/d cryogenic processing plant. We expect the new 60 MMcf/d processing plant to become operational in 2019.

Residue gas is delivered to the Colorado Interstate Gas pipeline and processed NGLs are delivered to the Overland Pass Pipeline.

The Niobrara G&P system currently provides midstream services for the DJ Basin reportable segment.

Permian Basin

The following table provides operating information regarding our Permian Basin reportable segment as of December 31, 2018.

| | Aggregate throughput capacity (MMcf/d) | Average daily MVCs through 2023 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) | Weighted-average remaining MVC life (Years) |
|---|---|---|---|---|---|
| Permian Basin (1) | 60 | n/a | n/a | 9.4 | n/a |

(1) Contract terms related to MVCs are excluded for confidentiality purposes.

AMIs for the Permian Basin reportable segment total more than 88,000 surface acres in the aggregate.

Summit Permian. The Summit Permian system is a newly-commissioned associated natural gas gathering and processing system located in the northern Delaware Basin in Eddy and Lea counties in New Mexico. Gathering and processing services on the Summit Permian system are provided pursuant to long-term, fee-based gathering agreements with producers that are primarily targeting crude oil production from the Bone Spring and Wolfcamp shale formations. XTO is the key customer of the Summit Permian system.

Summit Permian commissioned its initial assets, which comprise a low-pressure natural gas gathering system and a 60 MMcf/d cryogenic processing plant, in December 2018. Our processing complex will have the ability to be expanded to over 600 MMcf/d of processing capacity, as warranted, to meet customer needs. Over time, we expect to expand our midstream assets to accommodate ancillary services, including crude oil and produced water gathering.

Residue natural gas is delivered to the Transwestern Pipeline and processed NGLs are delivered to the Lone Star NGL Pipeline.

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## Piceance Basin

The following table provides operating information regarding our Piceance Basin reportable segment as of December 31, 2018.

| | Aggregate throughput capacity (MMcf/d) | Average daily MVCs through 2023 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) (1) | Weighted-average remaining MVC life (Years) (1) |
|---|---|---|---|---|---|
| Piceance Basin | 1,262 | 486 | 1,091 | 10.3 | 6.5 |

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Piceance Basin reportable segment total approximately 650,000 surface acres in the aggregate.

Grand River.  Grand River is primarily located in Garfield County, one of the largest natural gas producing counties in Colorado. The Grand River system provides gathering services pursuant to primarily long-term and fee-based agreements with multiple producers, including its key customers, Caerus and Terra. Volume throughput on the Grand River system is underpinned with

The Grand River system is primarily a low-pressure gathering system that gathers natural gas produced from directional wells targeting the liquids-rich Mesaverde formation. The Grand River system also gathers natural gas from our customers' wells targeting the Mancos and Niobrara shale formations, which underlie the Mesaverde formation, via a medium-pressure gathering system.

Natural gas gathered and/or processed on the Grand River system is compressed, dehydrated, processed and/or discharged to downstream pipelines serving (i) the Meeker Processing Complex, (ii) the Northwest Pipeline system and (iii) the TransColorado Pipeline system. Processed NGLs from Grand River are injected into the Mid-America Pipeline system or delivered to local markets. In addition, certain of our gathering agreements with our customers on the Grand River system permit us to retain condensate volumes that naturally discharge from the liquids-rich natural gas as it moves across our system.

The Grand River system currently provides midstream services for the Piceance Basin reportable segment.

Barnett Shale

The following table provides operating information regarding our Barnett Shale reportable segment as of December 31, 2018.

| Throughput capacity (MMcf/d) | Average daily MVCs through 2023 | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) (1) | Weighted-average remaining MVC life (Years) (1) |
|---|---|---|---|---|

| | | (MMcf/d) | | | |
|---|---|---|---|---|---|
| Barnett Shale | 480 | 6 | 11 | 6.6 | 0.8 |

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Barnett Shale reportable segment total more than 120,000 surface acres.

DFW Midstream. The DFW Midstream system is primarily located in southeastern Tarrant County, in north-central Texas. We consider this area to be the core of the core of the Barnett Shale because of the quality of the geology and the high production profile of the wells drilled to date. For example, the two largest and five of the 10 largest wells drilled in the Barnett Shale are connected to the DFW Midstream system. The DFW Midstream system is underpinned by a long-term, fee-based gathering agreement with Total and additional customers.

The DFW Midstream system includes natural gas gathering pipelines located under both private and public property and is partially located along existing electric transmission corridors. Compression on the system is powered by electricity. To offset the costs we incur to operate the system's electric-drive compressors, we either retain a fixed percentage of the natural gas that we gather or pass through a portion of the power expense to our customers.

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The DFW Midstream system currently has six primary interconnections with third-party, primarily intrastate pipelines. These interconnections enable us to connect our customers, directly or indirectly, with the major natural gas market hubs in Texas and Louisiana.

The DFW Midstream system currently provides midstream services for the Barnett Shale reportable segment.

Marcellus Shale

The following table provides operating information regarding our Marcellus Shale reportable segment as of December 31, 2018.

| | Throughput capacity (MMcf/d) | Average daily MVCs through 2023 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) | Weighted-average remaining MVC life (Years) |
|---|---|---|---|---|---|
| Marcellus Shale (1) | 1,050 | n/a | n/a | n/a | n/a |

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(1) Contract terms related to MVCs are excluded for confidentiality purposes.

Mountaineer Midstream. The Mountaineer Midstream system is located in Doddridge and Harrison counties in West Virginia where it gathers natural gas under a long-term, fee-based contract with Antero, which is targeting liquids-rich natural gas production from the Marcellus Shale formation. Volume throughput on the Mountaineer Midstream system is underpinned by MVCs from Antero.

The Mountaineer Midstream system, which is underpinned by a minimum revenue commitment from Antero, consists of a high-pressure natural gas gathering system and two compressor stations. This system gathers high-pressure natural gas received from upstream pipeline interconnections with Antero Midstream Partners, LP and Crestwood Equity Partners LP. Mountaineer Midstream serves as a critical inlet to the Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia and one of the largest natural gas processing facilities in the United States.

The Mountaineer Midstream system currently provides midstream services for the Marcellus Shale reportable segment.

For additional information relating to our business and gathering systems, see the "Trends and Outlook" and "Results of Operations" sections in Item 7. MD&A.

Regulation of the Natural Gas and Crude Oil Industries

General. Sales by producers of natural gas, crude oil, condensate and NGLs are currently made at market prices. However, gathering and transportation services are subject to various types of regulation, which may affect certain aspects of our business and the market for our services. FERC regulates the transportation of natural gas in interstate commerce and the interstate transportation of crude oil, petroleum products and NGLs. FERC regulation includes reviewing and accepting or approving rates and other terms and conditions for such transportation services. FERC is also authorized to prevent and sanction market manipulation in natural gas markets while the FTC is authorized to prevent and sanction market manipulation in petroleum markets. State and municipal regulations may apply to the production and gathering of certain natural gas, the construction and operation of natural gas and crude oil facilities and the rates and practices of gathering systems and intrastate pipelines.

Regulation of Crude Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and NGLs are not currently regulated and are transacted at market prices. In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. FERC, which has the authority under the NGA to regulate the prices and other terms and conditions of the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to its regulation, except interstate pipelines, to resell natural gas at market prices. Either Congress or FERC (with respect to the resale of gas in interstate commerce), however, could re-impose price controls in the future.

Exploration and production operations are subject to various types of federal, state and local regulation, including, but not limited to, permitting, well location, methods of drilling, well operations and conservation of resources. While these regulations do not directly apply to our business, they may affect our customers' ability to produce natural gas.

Regulation of the Gathering and Transportation of Natural Gas and Crude Oil. We believe that the majority of our natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC. On February 1, 2016, Epping's FERC tariff for interstate movements of crude oil on its Epping Pipeline in North Dakota became effective. That tariff is subject to FERC jurisdiction and oversight pursuant to FERC's authority under the ICA. Additionally, our proposed Double E Pipeline Project, which is currently in the pre-filing stage at FERC and is anticipated to provide natural gas transmission service from southeastern New Mexico to the Waha Hub in Texas will be subject to FERC jurisdiction once approved. We are also generally subject to FERC's anti-market manipulation regulations. The distinction between federally unregulated natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and changes in the policies and interpretations of laws and regulations. In addition, the status of any individual pipeline system may be determined by FERC on a case-by-case basis, although FERC has made no such determinations as to the status of our facilities. Consequently, the classification and regulation of pipeline systems (including some of our pipelines) could change based on future determinations by FERC or the courts.

Under FERC’s ICA jurisdiction, rates for interstate movements of liquids by pipeline are currently regulated primarily through an annual indexing methodology, under which pipelines increase or decrease their existing rates in accordance with a FERC-specified adjustment. This adjustment is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. FERC is currently considering a policy change that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC, although it has not yet made any determinations regarding these proposals.

Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through the indexing methodology by using a cost-of-service approach, but a pipeline must establish that a substantial divergence exists between its actual costs and the rates resulting from the indexing methodology. The rates charged by Epping may also be affected by an ongoing proceeding before FERC that seeks to address whether FERC’s existing policy of allowing partnership-owned pipelines to claim an income-tax allowance for partners’ tax liability results in an impermissible double-recovery, or whether justification exists to continue the current approach. The potential outcome of this proceeding is currently uncertain.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit Epping’s ability to set rates based on costs or could order reduced rates and reparations to complaining shippers for up to two years prior to the date of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

Intrastate pipelines, which may include some pipelines that perform gathering functions, may be subject to safety regulation by the DOT, although typically state regulatory authorities (operating under a federal certification) perform this function. State regulatory authorities also have jurisdiction over the rates and practices of intrastate pipelines and gathering systems, including requirements for ratable takes or non-discriminatory access to pipeline services. The basis for state regulation and the degree of regulatory oversight of gathering systems and intrastate pipelines varies from state to state. In Texas, we are regulated as a gas utility and have filed tariffs with the Railroad Commission of Texas to establish rates and terms of service for our DFW Midstream system assets. We have not been required to file tariffs in the other states in which we operate, although we are required to submit shape files and other information regarding the location and construction of underground gathering pipelines in North Dakota. The states in which we operate have adopted complaint-based regulation that allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve access issues and rate grievances, among other matters. State authorities in the states in which we operate generally have not initiated investigations of the rates or practices of gathering systems or intrastate pipelines in the absence of a complaint. State regulation of intrastate pipelines continues to evolve and may become more stringent in the future. For example, the North Dakota Industrial Commission recently adopted rule changes that resulted in additional construction and monitoring requirements for all pipelines, including, but not limited to, those that transport produced water, and has recently adopted reclamation bonding requirements for certain underground gathering pipelines in North Dakota.

Natural gas, crude oil and produced water production, gathering and transportation, including the construction of new gathering facilities and expansion of existing gathering facilities may also be subject to local regulation, such as approval and permit requirements.

Anti-Market Manipulation Rules. We are subject to the anti-market manipulation provisions in the NGA and the NGPA, as amended by the Energy Policy Act of 2005, which authorize FERC to impose fines of up to $1,238,271 per day per violation of the NGA, the NGPA, or their implementing regulations, subject to future adjustments for inflation. In addition, the FTC holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1,180,566 per violation, subject to future adjustment for inflation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The CFTC is directed under the CEA to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,098,190 per day per violation, subject to future adjustment for inflation, or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

Safety and Maintenance. We are subject to regulation by the DOT, which establishes federal safety standards for the design, construction, operation and maintenance of natural gas and crude oil pipeline facilities. In the Pipeline Safety Act of 1992, Congress expanded the DOT's regulatory authority to include regulated gathering lines that had previously been exempt from federal jurisdiction. The Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 established mandatory inspections for certain U.S. oil and natural gas transmission pipelines in high consequence areas. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 ("2011 Act") reauthorized funding for federal pipeline safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act reauthorized pipeline safety programs through 2019 and provided limited new authority, including the ability to issue emergency orders, while increasing transparency into the status of remaining actions required by the 2011 Act.

The DOT has delegated the implementation of pipeline safety requirements to PHMSA, which has adopted and enforces safety standards and procedures applicable to a limited number of our pipelines. In addition, many states, including the states in which we operate, have adopted regulations that are identical to or more restrictive than existing PHMSA regulations for intrastate pipelines. Among the regulations applicable to us, PHMSA requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high-population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW Midstream system is located. While the majority of our pipelines meet the DOT definition of gathering lines and are thus currently exempt from the integrity management requirements of PHMSA, we also operate a limited number of pipelines that are subject to the integrity management requirements. Those regulations require operators, including 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;

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- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

In April 2016, PHMSA proposed changes to gas pipeline safety regulations that would impose expanded assessment requirements, expand assessment and repair requirements to pipelines in areas with medium population densities (so-called "Moderate Consequence Areas"), and extend pipeline safety regulation to certain previously unregulated gas gathering pipelines. PHMSA has yet to finalize this rulemaking, however, and the timing and content of any final rule are uncertain. In 2015, PHMSA adopted regulations that impose pipeline incident prevention and response measures on pipeline operators and in 2012, PHMSA issued an Advisory Bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. Pipelines that do not meet PHMSA's record verification standards may be required to perform additional testing or reduce their operating pressures.

In January 2017, PHMSA issued a final rule amending its pipeline safety regulations for the design, construction, testing, operation, and maintenance of pipelines transporting hazardous liquids. Among other things, the final rule extends certain safety-related condition reporting requirements to all hazardous liquid gathering lines and requires periodic assessments of certain hazardous liquid transmission lines in non-high consequence areas. The status of this rulemaking is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017, pursuant to which all regulations that had been sent to the Office of the Federal Register, but not yet published, were withdrawn for further review. Accordingly, the anticipated January 2017 rulemaking was never published in the Federal Register, and the rule is not currently effective.

Gathering systems like ours are also subject to a number of federal and state laws and regulations, including the Federal Occupational Safety and Health Act and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the Occupational Safety and Health Administration hazard communication standard, EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and the public.

Environmental Matters

General. Our operation of pipelines and other assets for the gathering, treating and/or processing of natural gas and the gathering of crude oil and produced water is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these assets, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits or permit requirements issued pursuant to or imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to

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file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more stringent requirements, resulting in more restrictions and limitations, on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing and future regulations.

The following is a discussion of the material environmental laws and regulations that relate to our business.

Hazardous Substances and Waste. Our operations are subject to environmental laws and regulations relating to the management and release of solid and hazardous wastes and other substances, including hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. Furthermore, the Toxic Substances Control Act and analogous state laws, impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the RCRA and comparable state statutes. While the RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Although we generate minimal hazardous waste, it is possible that non-hazardous wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and, therefore, be subject to more rigorous and costly disposal requirements. Moreover, from time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for non-hazardous wastes, including natural gas wastes.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although we believe that the previous operators utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal, without our knowledge. These properties and the wastes disposed thereon may be subject to CERCLA, the RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Air Emissions. Our operations are subject to the federal CAA and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring, control and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and criminal enforcement actions. Furthermore, we may be required to incur certain capital expenditures in the future to obtain and maintain operating permits and approvals for air pollutant emitting sources.

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In October 2015, the EPA issued a new lower NAAQS for ozone. The previous ozone standard was set at 75 parts per billion ("ppb"). The revised standard has been lowered to 70 ppb. The lowered ozone NAAQS could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate, which could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements and increased permitting delays and costs. Impacts from the new standard have not yet been determined, as states are still in the process of incorporating the new standard into their respective state implementation plans. We will continue to monitor developments to determine if any adverse effects on our operations can be expected.

On June 3, 2016, the EPA finalized revisions to its 2012 New Source Performance Standard ("NSPS") OOOO for the oil and gas industry, to reduce emissions of greenhouse gases - most notably methane - along with smog-forming VOCs. The revisions, which are published in the Federal Register under Subpart OOOOa, included the addition of methane to the pollutants covered by the rule, along with requirements for detecting and repairing leaks at gathering and boosting stations. The revised rule applies to sources that have been modified, constructed, or reconstructed after September 18, 2015. EPA is currently reconsidering NSPS OOOOa and has proposed to stay its requirements. However, the rule currently remains in effect. While we do not expect this rule to significantly impact our existing operations, future modifications or new construction may be adversely affected by the revised rule.

On November 16, 2016 the Bureau of Land Management ("BLM") issued a final rule to reduce venting and flaring of natural gas on public and Indian lands. The final rule mirrors many of the requirements found in NSPS OOOOa, with additional natural gas royalty requirements for flared volumes at sites already connected to gas capture infrastructure. In December 2017, the BLM issued a final rule that temporarily suspends or delays these requirements until January 2019, while BLM considers revising or rescinding these requirements. While the rule is expected to have little or no direct impact on our operations, our customers that are primarily upstream wellhead operators may be impacted by the requirements in this rule.

Water Discharges.  The CWA and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters, which impacts our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits require us to control storm water runoff from some of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. Except as otherwise disclosed in this annual report, we believe that we are in substantial compliance with all applicable requirements of the CWA and analogous state laws and regulations relating to water discharges.

Oil Pollution Act.  The OPA requires the preparation of an SPCC plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security and training. Certain of our facilities are classified as SPCC-regulated facilities. We believe that they are in substantial compliance with all applicable requirements of OPA.

Hydraulic Fracturing.  Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations and is primarily presently regulated by state agencies. However, Congress has in the past and may in the future consider legislation to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing. A number of states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure and well

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construction requirements on oil and/or natural gas drilling activities. For example, a Colorado ballot initiative, Proposition 112, would have substantially increased setback distances for various upstream activities, thereby substantially restricting new oil and gas development in the state. Although Proposition 112 was defeated in the November 2018 elections, similar efforts in Colorado and elsewhere, if passed, could restrict oil and gas development in the future. States also could elect to prohibit hydraulic fracturing altogether, as New York, Maryland, and Vermont have done. In addition, certain local governments have adopted, and additional local governments may adopt, ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

The EPA has also moved forward with various regulatory actions, including approving new regulations requiring green completions of hydraulically-fractured wells and corresponding reporting requirements that went into effect in 2015. Revisions to the green completion regulations were finalized in June 2016 and include additional requirements to reduce methane and VOCs. The EPA announced in April 2017 that it would review these regulations and has proposed to stay their requirements. However, the regulations currently remain in effect. The BLM has also asserted regulatory authority over aspects of the hydraulic fracturing process, and issued a final rule in March 2015 that established more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. The rescission rule is currently subject to a legal challenge. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. Some state regulatory agencies, including those in Colorado, Ohio, and Texas, have modified their regulations or guidance to account for induced seismicity. These developments could result in additional regulation and restrictions on the use of injection disposal wells and hydraulic fracturing. Such regulations and restrictions could cause delays and impose additional costs and restrictions on our customers.

If new or more stringent federal, state or local legal restrictions relating to drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil that our customers produce, and could thereby adversely affect our revenues and results of operations. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for our customers, which could ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species.

National Environmental Policy Act. The NEPA establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. Major projects having the potential to significantly impact the environment require review under NEPA. Many of our activities are covered under categorical exclusions which results in an expedited NEPA review process. Large upstream and downstream projects with significant cumulative impacts may be subject to longer NEPA review processes, which could impact the timing of those projects and our services associated with them.

Climate Change. The EPA has adopted regulations under the CAA that, among other things, establish GHG emission limits from motor vehicles as well as establish PSD construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis.

EPA rules also require the reporting of GHG emissions from specified large GHG-emitting sources in the United States, including onshore and offshore oil and natural gas systems. We are required to report under these rules for

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our assets that have GHG emissions above the reporting thresholds. In October 2015, the EPA issued revisions to Subpart W of the GHG reporting rule to include reporting requirements for gathering and booster stations, onshore natural gas transmission pipelines, and completions and workovers of oil wells with hydraulic fracturing. This development resulted in increased monitoring and reporting for our operations and for upstream producers for whom we provide midstream services.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global GHG emissions. The agreement entered into force in November 2016, after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. In August 2017, the United States formally documented to the United Nations its intent to withdraw from the agreement. The earliest possible effective withdrawal date from the agreement is November 2020.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG-emitting energy sources, our products would become more desirable in the market with more stringent limitations on GHG emissions. Conversely, to the extent that our products are competing with lower GHG-emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions.

Other Information

Employees.  SMLP does not have any employees. All of the employees required to conduct and support its operations are employed by Summit Investments, but these individuals are sometimes referred to as our employees. The officers of our General Partner manage our operations and activities. As of December 31, 2018, Summit Investments employed 330 people who provide direct, full-time support to our operations. None of our employees are covered by collective bargaining agreements, and we have never experienced any business interruption as a result of any labor disputes.

Availability of Reports.  We make certain filings with the SEC, including, among other filings, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through our website, www.summitmidstream.com, as soon as reasonably practicable after the date they are filed with, or furnished to, the SEC. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC through the SEC’s website, http://www.sec.gov. Our press releases and recent investor presentations are also available on our website.

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Item 1A. Risk Factors.

Item 1A. Risk Factors is divided into the following sections:



Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements of expenses incurred on our behalf by our General Partner, to enable us to maintain or increase the distributions to holders of our common units.

We may not have sufficient available cash from operating surplus each quarter to maintain or increase the distributions to holders of our common units and we expect to reduce our common unit distribution from $0.575 for the quarter ended December 31, 2018 to $0.2875 for the quarter ending March 31, 2019. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volumes we gather, treat and process;
- the level of production of natural gas and crude oil (and associated volumes of produced water) from wells connected to our gathering systems, which is dependent in part on the demand for, and the market prices of, crude oil, natural gas and NGLs;
- damage to pipelines, facilities, related equipment and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters, accidents and acts of terrorism;
- leaks or accidental releases of hazardous materials into the environment;
- weather conditions and seasonal trends;
- changes in the fees we charge for our services;
- changes in contractual MVCs;
- the level of competition from other midstream energy companies in our areas of operation;
- changes in the level of our operating, maintenance and general and administrative expenses;
- regulatory action affecting the supply of, or demand for, crude oil, natural gas and NGLs, the fees we can charge, how we contract for services, our existing contracts, our operating and maintenance costs or our operating flexibility; and
- prevailing economic and market conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level and timing of capital expenditures we make;
- the level of our operating, maintenance and general and administrative expenses, including reimbursements of expenses incurred on our behalf by our General Partner;
- the cost of acquisitions, if any;
- our ability to sell assets, if any, and the price that we may receive for such assets;
- our debt service requirements and other liabilities, including the Deferred Purchase Price Obligation;

• fluctuations in our working capital needs;

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- our ability to borrow funds and access the debt and equity capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our General Partner;
- not receiving anticipated shortfall payments from our customers;
- adverse legal judgments, fines and settlements;
- distributions paid on our Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units"); and
- other business risks affecting our cash levels.

We depend on a relatively small number of customers for a significant portion of our revenues. The loss of, or material nonpayment or nonperformance by, or the curtailment of production by, any one or more of these customers could materially adversely affect our revenues, cash flows and ability to make cash distributions to our unitholders.

Certain of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of these customers could have a material adverse effect on our revenues and cash flows and our ability to make cash distributions to our unitholders. We expect our exposure to concentrated risk of nonpayment or nonperformance to continue as long as we remain substantially dependent on a relatively small number of customers for a significant portion of our revenues.

If our customers curtail or reduce production in our areas of operation, it could reduce throughput on our system and, therefore, materially adversely affect our revenues, cash flows and ability to make cash distributions to our unitholders.

We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties and any material nonpayment or nonperformance by one or more of these parties could materially adversely affect our financial and operating results.

Although we attempt to assess the creditworthiness and associated liquidity of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. In addition, there can be no assurance that our contract counterparties will perform or adhere to existing or future contractual arrangements, including making any required shortfall payments or other payments due under their respective contracts.

The policies and procedures we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, if necessary, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our policies and procedures prove to be inadequate, our financial and operational results may be negatively impacted.

Some of our counterparties may be highly leveraged, have limited financial resources and/or have recently experienced a rating agency downgrade and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices could have a negative impact on our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us.

Any material nonpayment or nonperformance by any of our counterparties or suppliers could require us to pursue substitute counterparties or suppliers for the affected operations or reduce our operations. There can be no assurance that any such efforts would be successful or would provide similar financial and operational results.

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**Adverse developments in our areas of operation could materially adversely impact our financial condition, results of operations and cash flows and reduce our ability to make cash distributions to our unitholders.**

Our operations are focused on gathering, treating and processing services in the following unconventional resource basins, primarily shale formations: the Utica Shale, the Williston Basin, the DJ Basin and the Permian Basin. Due to our limited industry diversity, adverse developments in the natural gas and crude oil industries or in our existing areas of operation could have a significantly greater impact than if we did not have such limited diversity on our financial condition, results of operations and cash flows.

Significant prolonged weakness in natural gas, NGL and crude oil prices could reduce throughput on our systems and materially adversely affect our revenues and cash available to make cash distributions to our unitholders.

Lower natural gas, NGL and crude oil prices could negatively impact exploration, development and production of natural gas and crude oil, thereby resulting in reduced throughput on our gathering systems. Additionally, certain of our customers in each of our areas of operations have reduced, and others could reduce, drilling activity and capital expenditure budgets. If natural gas, NGL and/or crude oil prices remain at current levels or decrease, it could cause sustained reductions in exploration or production activity in our areas of operation and result in a further reduction in throughput on our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make cash distributions to our unitholders. Additionally, we expect our natural gas and crude oil marketing services to increase in future periods, resulting in higher exposure to direct commodity price risk.

Because of the natural decline in production from our customers' existing wells, our success depends in part on our customers replacing declining production and also on our ability to maintain levels of throughput on our systems. Any decrease in the volumes that we gather and process could materially adversely affect our business and operating results.

The customer volumes that support our business depend on the level of production from natural gas and crude oil wells connected to our systems, the production from which may be less than expected and will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our systems, we must obtain new sources of volume throughput. The primary factors affecting our ability to obtain new sources of volume throughput include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for new volumes on our systems.

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. In addition, we have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected hydrocarbon commodity prices;
- demand for crude oil, natural gas and other hydrocarbon products, including NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

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Fluctuations in energy prices can also greatly affect the development of new crude oil and natural gas reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of crude oil, natural gas and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic and geopolitical conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas ("LNG");
- the ability to export LNG;
- the availability of transportation and storage systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials and premiums;
- the price and availability of alternative fuels, including alternative fuels that benefit from government subsidies;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of crude oil, natural gas and other hydrocarbon products, including NGLs.

Because of these factors, even if new crude oil or natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, those reductions could reduce our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering, treating and processing assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, revenues associated with these assets will decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures over time, which will reduce our cash available for distribution.

Many of our costs are fixed and do not vary with our throughput. These costs will not decline ratably or at all should we experience a reduction in throughput, which could result in a decline in our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.

Any significant decrease in the demand for natural gas and crude oil could reduce the volumes of natural gas and crude oil that we gather and process, which could adversely affect our business and operating results.

The volumes of natural gas and crude oil that we gather and process depend on the supply and demand for natural gas and crude oil and other hydrocarbon products in the areas served by our assets. Natural gas and crude oil compete with other forms of energy available to users, including electricity, coal, other fuels and alternative energy. Increased demand for such forms of energy at the expense of natural gas and crude oil could lead to a reduction in demand for our services. Any such reduction could result in a decline in our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.

**If our customers do not increase the volumes they provide to our gathering systems, our growth strategy and ability to increase cash distributions to our unitholders may be materially adversely affected.**

If we are unsuccessful in attracting new customers and/or new gathering opportunities with existing customers, our ability to increase cash distributions to our unitholders will be impaired. Our customers are not obligated to provide additional volumes to our gathering systems, and they may determine in the future that drilling activities in areas outside of our current areas of operation are strategically more attractive to them. Reductions by our customers in our areas of mutual interest could result in reductions in throughput on our systems and materially adversely impact our ability to grow our operations and increase cash distributions to our unitholders.

Certain of our gathering and processing agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

We designed those gathering and processing agreements that contain MVC provisions to generate stable cash flows for us over the life of the MVC contract term while also minimizing our direct commodity price risk. Under certain of these MVCs, our customers agree to ship a minimum volume on our gathering systems or send a minimum volume to our processing plants or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. In addition, our gathering and processing agreements may also include an aggregate MVC, which represents the total amount that the customer must flow on our gathering system or send to our processing plants (or an equivalent monetary amount) over the MVC term. If such customer's actual throughput volumes are less than its MVC for the contracted measurement period, it must make a shortfall payment to us at the end of the applicable measurement period. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable fee. To the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period, certain of our gathering agreements contain provisions that allow the customer to use the excess volumes or the shortfall payment to credit against future excess volumes or future shortfall payments, which could have a material adverse effect on our results of operations, financial condition and cash flows and our ability to make cash distributions to our unitholders.

We have not obtained independent evaluations of all of the reserves connected to our gathering systems; therefore, in the future, customer volumes on our systems could be less than we anticipate.

We have not obtained independent evaluations of all of the reserves connected to our systems. Moreover, even if we did obtain independent evaluations of all of the reserves connected to our systems, such evaluations may prove to be incorrect. Crude oil and natural gas reserve engineering requires subjective estimates of underground accumulations of crude oil and natural gas and assumptions concerning future crude oil and natural gas prices, future production levels and operating and development costs.

Accordingly, we may not have accurate estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional volumes, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our industry is highly competitive, and increased competitive pressure could materially adversely affect our business and operating results.

We compete with other midstream companies in our areas of operations, some of which are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors may have assets in closer proximity to natural gas and crude oil supplies and may have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering systems that would create additional competition for the services we provide to our customers. Because our customers do not have leases that cover the entirety of our areas of mutual interest, non-customer producers that lease acreage within any of our areas of mutual interest may choose to use one of our competitors for their gathering and/or processing service needs.

In addition, our customers may develop their own gathering systems outside of our areas of mutual interest. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be materially 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 cash distributions to our unitholders.

We may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis.

Our gathering, treating and processing contracts have terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing customers or enter into new contracts with other customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. Moreover, we may be unable to obtain areas of mutual interest from new customers in the future, and we may be unable to renew existing areas of mutual interest with current customers as and when they expire. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide gathering and/or processing services in our areas of operation;
- the macroeconomic factors affecting gathering, treating and processing economics for our current and potential customers;
- 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 areas of operation 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.

To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenues and cash flows could decline and our ability to make cash distributions to our unitholders could be materially adversely affected.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenues and cash flows and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the natural gas, crude oil and produced water that we gather and/or process, our revenues, cash flows and ability to make cash distributions to our unitholders could be materially adversely affected.

We have a relatively limited ownership history with respect to certain of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and operating results.

We have a relatively limited history of operating certain of our assets. There may be historical occurrences or latent issues regarding certain of our pipeline systems of which we may be unaware and that may have a material adverse effect on our business and results of operations. Any significant increase in maintenance and repair expenditures or loss of revenue due to the condition of our pipeline systems could materially adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

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**Crude oil and natural gas production and gathering may be adversely affected by weather conditions and terrain, which in turn could negatively impact the operations of our gathering, treating and processing facilities and our construction of additional facilities.**

Extended periods of below freezing weather and unseasonably wet weather conditions, especially in North Dakota, Ohio and West Virginia, can be severe and can adversely affect crude oil and natural gas operations due to the potential shut-in of producing wells or decreased drilling activities. These types of interruptions could result in a decrease in the volumes supplied to our gathering systems. Further, delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering, treating and processing systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our customers and thereby give rise to certain termination rights and/or the release of dedicated acreage. Any resulting terminations or releases could materially adversely affect our business and results of operations.

We also may be required to incur additional costs and expenses in connection with the design and installation of our facilities due to their location and surrounding terrain. We may be required to install additional facilities, incur additional capital and operating expenditures, or experience interruptions in or impairments of our operations to the extent that the facilities are not designed or installed correctly. For example, certain of our pipeline facilities are located in mountainous areas such as our Utica Shale and Marcellus Shale operations, which may require specially designed facilities and special installation considerations. If such facilities are not designed or installed correctly, do not perform as intended, or fail, we may be required to incur significant expenditures to correct or repair the deficiencies, or may incur significant damages to or loss of facilities, and our operations may be interrupted as a result of deficiencies or failures. In addition, such deficiencies may cause damage to the surrounding environment, including slope failures, stream impacts and other natural resource damages, and we may as a result also be subject to increased operating expenses or environmental penalties and fines.

Interruptions in operations at any of our facilities may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed and constructed. Any significant interruption at any of our gathering, treating or processing facilities, or in our ability to provide gathering, treating or processing services, could adversely affect our operations and cash flows available for distribution to our unitholders. Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at our physical plants or pipeline facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of resources necessary to operate our midstream facilities;
- damage to our facilities resulting from production volumes that do not comply with applicable specifications; and
- inadequate transportation and/or market access to support production volumes, including lack of pipeline, rail terminals, produced water disposal facilities and/or third-party processing capacity.

Any significant interruption at any of our gathering, treating or processing facilities, or in our ability to provide gathering, treating or processing services, could adversely affect our operations and cash flows available for distribution to our unitholders.

**Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant incident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant incidents or events for which we are insured, our operations and financial results could be materially adversely affected.**

Our operations are subject to all of the risks and hazards inherent in the operation of gathering, treating and processing systems, including:

- damage to pipelines, processing plants, compression assets, related equipment and surrounding properties caused by tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks or losses resulting from the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of certain of our systems in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the damages resulting from these risks.

These risks may also result in curtailment or suspension of our operations. A natural disaster or any event such as those described above affecting the areas in which we and our customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on portions or all of our gathering systems. Potential customer impacts arising from service interruptions on segments of our gathering systems could include limitations on our ability to satisfy customer requirements, obligations to temporarily waive minimum volume commitments during times of constrained capacity, temporary or permanent release of production dedications, and solicitation of existing customers by others for potential new projects that would compete directly with our existing services. Such circumstances could materially adversely impact our ability to meet contractual obligations and retain customers, with a resulting negative impact on our business and results of operations and our ability to make cash distributions to our unitholders.

Our insurance coverage is provided by policies that cover us and Summit Investments. Therefore, it is possible that a claim by Summit Investments could exhaust claim capacity and leave SMLP and its subsidiaries exposed to risk of loss should they experience a loss during the same policy cycle. In addition, although we have a range of insurance programs providing varying levels of protection for public liability, damage to property, loss of income and certain environmental hazards, we may not be insured against all causes of loss, claims or damage that may occur. If a significant incident or event occurs for which we are not fully insured, it could materially adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates and/or claims by Summit Investments may increase rates on all of the insured-asset group, including those owned by SMLP and its subsidiaries. As a result of industry or market conditions, some of which are beyond our control, 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, with regard to the assets we have acquired, we have limited indemnification rights to recover from the seller of the assets in the event of any potential environmental liabilities.

We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from third parties, our future growth will be affected, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations. Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations. The acquisition component of our strategy also relies, in part, on the continued divestiture of midstream assets by industry participants. A material decrease in such divestitures would limit our

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**opportunities for future acquisitions and could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.**

If we are unable to make accretive acquisitions from third parties, whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts; (ii) unable to obtain financing for these acquisitions on economically acceptable terms; (iii) outbid by competitors; or (iv) unable to obtain necessary governmental or third-party consents or for any other reason, then our future growth and ability to increase cash distributions on a per-unit basis will be limited. If we are unable to acquire assets from third parties in the near or long term it may adversely affect our ability to grow our business. Even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations. Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies and potential growth;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- the risk that natural gas or crude oil reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated or at all;
- an inability to successfully integrate the assets or businesses we acquire;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- mistaken assumptions about the overall costs of debt or equity capital;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines;
- customer or key employee losses at the acquired businesses;
- higher-than-anticipated production declines; and
- improperly constructed facilities.

If we consummate any future acquisitions, our capitalization, results of operations and future growth may change significantly and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in deciding to engage in these future acquisitions, which may reduce, rather than increase, our cash generated from operations.

All of the assets owned by Summit Investments have been contributed to the Partnership in connection with prior drop down transactions and, as a result, our growth strategy has become more dependent on making acquisitions from third parties. This shift from a growth strategy focused, primarily, on acquisitions from Summit Investments, to one focused, primarily, on third-party acquisitions could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

We may fail to successfully integrate gathering system acquisitions into our existing business in a timely manner, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders, or fail to realize all of the expected benefits of the acquisitions, which could negatively impact our future results of operations.

Integration of future gathering system acquisitions could be a complex, time-consuming and costly process, particularly if the acquired assets significantly increase our size and/or (i) diversify the geographic areas in which we operate or (ii) the service offerings that we provide.

The failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. If any of the risks described above or in the immediately preceding risk factor or unanticipated liabilities or costs were to materialize with respect to future acquisitions or if the acquired assets were to perform at levels below the forecasts we used to evaluate them, then the anticipated benefits from the acquisition may not be fully realized, if at all, and our future results of operations and ability to make cash distributions to unitholders could be negatively impacted.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could materially adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through organic growth projects such as the construction of the new natural gas processing infrastructure in the DJ Basin and Permian Basin. The construction of additions or modifications to our existing systems, including our expanded processing facilities in the DJ Basin, and the construction of new midstream assets, including our newly commissioned processing plant in the Permian Basin, involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control.

Such expansion projects may also require the expenditure of significant amounts of capital, and financing, traditional or otherwise, may not be available on economically acceptable terms or at all. If we undertake these projects, our revenue may not increase immediately upon the expenditure of funds for a particular project and they may not be completed on schedule, at the budgeted cost, or at all.

Moreover, we could construct facilities to capture anticipated future production growth in a region where such growth does not materialize or only materializes over a period materially longer than expected. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate due to the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could materially adversely affect our results of operations and financial condition.

In addition, the construction of additions or modifications to our existing gathering, treating and processing assets and the construction of new midstream assets may require us to obtain federal, state, and local regulatory environmental or other authorizations. The approval process for gathering, treating and processing activities has become increasingly challenging, due in part to state and local concerns related to unregulated exploration and production and gathering, treating and processing activities in new production areas. Such authorization may not be granted or, if granted, such authorization may include burdensome or expensive conditions. As a result, we may be unable to obtain such authorizations and may, therefore, be unable to connect new volumes to our systems or capitalize on other attractive expansion opportunities. A future government shutdown could delay the receipt of any federal regulatory approvals. Additionally, it may become more expensive for us to obtain authorizations or to renew existing authorizations. If the cost of renewing or obtaining new authorizations increases materially, our cash flows could be materially adversely affected.

We require access to significant amounts of additional capital to implement our growth strategy, as well as to meet potential future capital requirements under certain of our gathering and processing agreements. Limited access and/or availability of the debt and equity capital markets could impair our ability to grow or cause us to be unable to meet future capital requirements.

To expand our asset base, whether through acquisitions or organic growth, we will need to make expansion capital expenditures. We also frequently consider and enter into discussions with third parties regarding potential acquisitions. In addition, the terms of certain of our gathering and processing agreements also require us to spend significant amounts of capital, over a short period of time, to construct and develop additional midstream assets to support our customers' development projects. Depending on our customers' future development plans, it is possible that the capital required to construct and develop such assets could exceed our ability to finance those expenditures using our cash reserves or available capacity under our Revolving Credit Facility.

We plan to use cash from operations, incur borrowings and/or sell additional common units or other securities to fund our future expansion capital expenditures. Using cash from operations to fund expansion capital expenditures will directly reduce our cash available for distribution to unitholders. Our ability to obtain financing or to access the capital markets for future debt or equity offerings may be limited by (i) our financial condition at the time of any such financing or offering, (ii) covenants in our debt agreements, (iii) restrictions imposed by our Series A Preferred Units; (iv) general economic conditions and contingencies, (v) the impact of any secondary offering of common units by Summit Investments or the Sponsor and (vi) general weakness in the debt and equity capital markets and other uncertainties that are beyond our control. Furthermore, we do not have a contractual commitment from our Sponsor or Summit Investments to provide any direct or indirect financial assistance to us. Furthermore, market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our expansion capital expenditures and acquisition capital expenditures with the issuance of additional equity. We recently announced a planned reduction in our common unit distribution, and this reduction may further reduce demand for our common units. As such, if we are unable to raise expansion capital, we may lose the opportunity to make acquisitions, pursue new organic development projects, or to gather, treat and process new production volumes from our customers with whom we have agreed to construct and develop midstream assets in the future. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional units representing limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

Because our common units are yield-oriented securities, increases in interest rates could materially adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions to our unitholders.

Interest rates are generally near historic lows and may increase in the future. While borrowing costs came down for the oil and natural gas industry as a whole, the Federal Reserve announced that it raised its benchmark federal-funds rate from 1.25% and 1.50% to a range between 2.25% and 2.50% in December 2018. As a result, interest rates on our future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have a material adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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

At December 31, 2018, we had $1.27 billion of indebtedness outstanding and the unused portion of our $1.25 billion Revolving Credit Facility totaled $784.0 million. Our future level of debt could have significant consequences, including among other things:

- limiting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes and/or obtaining such financing on favorable terms;
- reducing our funds available for operations, future business opportunities and cash distributions to unitholders by that portion of our cash flow required to make interest payments on our debt;
- increasing our vulnerability to competitive pressures or a downturn in our business or the economy generally; and

- limiting our flexibility in responding to changing business and economic conditions.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions,

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investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

Restrictions in our Revolving Credit Facility and Senior Notes indentures could materially adversely affect our business, financial condition, results of operations, ability to make cash distributions to unitholders and value of our common units.

We are dependent upon the earnings and cash flows generated by our operations to meet our debt service obligations and to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our Revolving Credit Facility, our Senior Notes indentures and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders. For example, our Revolving Credit Facility and Senior Notes indentures, taken together, restrict our ability to, among other things:

- incur or guarantee certain additional debt;
- make certain cash distributions on or redeem or repurchase certain units;
- make certain investments and acquisitions;
- make certain capital expenditures;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- enter into sale and lease-back transactions and certain operating leases;
- merge or consolidate with another company or otherwise engage in a change of control transaction; and
- transfer, sell or otherwise dispose of certain assets.

Our Revolving Credit Facility and Senior Notes indentures also contain covenants requiring us to maintain certain financial ratios and meet certain tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot guarantee that we will meet those ratios and tests.

The provisions of our Revolving Credit Facility and Senior Notes indentures may affect our ability to obtain future financing and pursue attractive business opportunities as well as affect 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 Senior Notes indentures could result in a default or an event of default that could enable our lenders and/or senior noteholders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, the lenders under our Revolving Credit Facility could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. The Revolving Credit Facility also has cross default provisions that apply to any other indebtedness we may have and the Senior Notes indentures have cross default provisions that apply to certain other indebtedness.

A portion of our revenues are directly exposed to changes in crude oil, natural gas and NGL prices, and our exposure may increase in the future.

During the year ended December 31, 2018, we derived 27% of our revenues from (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River systems, (ii) natural gas and crude oil marketing services in and around our gathering systems, (iii) the sale of natural gas we retain from certain DFW Midstream customers and (iv) the sale of condensate we retain from our gathering services at Grand River. Consequently, our existing operations and cash flows have direct exposure to commodity price risk. Although we will seek to limit our commodity price exposure with new customers in the future, our efforts to obtain fee-based contractual terms may not be successful or the local market for our services may not support fee-based gathering and processing agreements. For example, we have percent-of-proceeds contracts with certain natural gas producer customers and we may, in the future, enter into additional percent-of-proceeds contracts with these customers or other customers or enter into keep-whole arrangements, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of the underlying commodities.

Furthermore, we may acquire or develop additional midstream assets in the future that have a greater exposure to fluctuations in commodity price risk than our current operations. Future exposure to the volatility of natural gas and crude oil prices could have a material adverse effect on our business, results of operations and financial condition. For example, for a small portion of the natural gas gathered on our systems, we purchase natural gas from producers prior to delivering the natural gas to pipelines where we typically resell the natural gas under arrangements including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices. If we expand the implementation of such natural gas purchase and sale arrangements within our business, such fluctuations could materially affect our business.

A change in laws and regulations applicable to our assets or services, or the interpretation or implementation of existing laws and regulations may cause our revenues to decline or our operation and maintenance expenses to increase.

Various aspects of our operations are subject to regulation by the various federal, state and local departments and agencies that have jurisdiction over participants in the energy industry. The regulation of our activities and the natural gas and crude oil industries frequently change as they are reviewed by legislators and regulators. In 2016, the North Dakota Industrial Commission adopted rule changes that resulted in additional construction and monitoring requirements for certain underground gathering pipelines, including, but not limited to, those that transport produced water. The NDIC also adopted reclamation bonding requirements for certain underground gathering pipelines. In 2016, the DOT, through PHMSA, proposed changes to gas pipeline safety regulations that would impose expanded assessment requirements, expand assessment and repair requirements to pipelines in areas with medium population densities (so-called “Moderate Consequence Areas”), and extend pipeline safety regulation to previously unregulated gas gathering pipelines. PHMSA has yet to finalize this rulemaking, however, and the timing and contents of any final rule are uncertain. Then, in January 2017, PHMSA issued a final rule, which was withdrawn as a result of the Trump administration's regulatory freeze, amending its pipeline safety regulations for hazardous liquids pipelines, and which, among other things, would have extended certain safety-related reporting requirements to hazardous liquid gathering lines and required periodic assessments of certain hazardous liquid transmission lines in non-high consequence areas; the rule is not currently effective, but could be reissued by PHMSA. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. In November 2018, PHMSA also increased the maximum penalties for violating federal safety standards, which are subject to future increases to account for inflation. In addition, the adoption of proposals for more stringent legislation, regulation or taxation of drilling activity could directly curtail such activity or increase the cost of drilling, resulting in reduced levels of drilling activity and therefore reduced demand for our services. For example, in 2018 the Colorado state ballot included a proposed 2,500 foot setback for oil and gas development from occupied structures and certain other areas. While the proposal did not pass, similar proposals in the future are likely. Regulatory agencies establish and, from time to time, change priorities, which may result in additional burdens on us, such as additional reporting requirements and more frequent audits of operations. Our operations and the markets in which we participate are affected by these laws, regulations and interpretations and may be affected by changes to them or their implementation, which may cause us to realize materially lower revenues or incur materially increased operation and maintenance costs or both.

Increased regulation of hydraulic fracturing could result in reductions or delays in customer production, which could materially adversely impact our revenues.

Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily regulated by state agencies. However, Congress has in the past, and may in the future consider legislation to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing. A number of states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. For example, a Colorado ballot initiative, Proposition 112, would have substantially increased setback distances for various upstream activities, thereby substantially restricting new oil and gas development in the state. Although Proposition 112 was defeated in the November 2018 elections, similar efforts in Colorado and elsewhere, if passed, could restrict oil and gas development in the future. States also could elect to prohibit hydraulic fracturing altogether, as New York, Maryland, and Vermont have done. In addition, certain local governments have adopted, and additional local governments may adopt, ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

The EPA has also moved forward with various regulatory actions, including approving new regulations requiring green completions of hydraulically-fractured wells and corresponding reporting requirements (NSPS OOOO) that went into effect in 2015. Revisions to the green completion regulations (NSPS OOOOa) were finalized in June 2016 and include additional requirements to reduce methane and VOCs. In October 2018, the EPA published a proposed rule that would amend certain requirements of NSPS OOOOa. Among other things, the proposed rule would reduce monitoring frequencies for fugitive emissions and clarify and streamline certain other requirements. However, the 2016 regulations currently remain in effect. The BLM has also asserted regulatory authority over aspects of the hydraulic fracturing process, and issued a final rule in March 2015 that established more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. The rescission rule is currently subject to a legal challenge. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. Some state regulatory agencies, including those in Colorado, Ohio, and Texas, have modified their regulations or guidance to account for induced seismicity. These developments could result in additional regulation and restrictions on the use of injection disposal wells and hydraulic fracturing. Such regulations and restrictions could cause delays and impose additional costs and restrictions on our customers.

If new or more stringent federal, state or local legal restrictions relating to drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil that our customers produce, and could thereby adversely affect our revenues and results of operations. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for our customers, which could ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

We are subject to FERC jurisdiction, federal anti-market manipulation laws and regulations, potentially other federal regulatory requirements and state and local regulation, and could be materially affected by changes in such laws and regulations, or in the way they are interpreted and enforced.

We believe that our natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC under the NGA and the NGPA. Interstate movements of crude oil on the Epping Pipeline in North Dakota are subject to FERC jurisdiction under the ICA. Additionally, our proposed Double E Pipeline Project, which is currently in the pre-filing stage at FERC and is anticipated to provide natural gas transmission service from southeastern New Mexico to the Waha Hub in Texas, will be subject to FERC jurisdiction once approved. We are also generally subject to the anti-market manipulation provisions in the NGA, as amended by the Energy Policy Act of 2005, and to FERC's regulations thereunder, which authorize FERC to impose fines of up to $1,269,500 per day per violation of the NGA or its implementing regulations, subject to future adjustment for inflation. In addition, the FTC holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in oil markets, and has adopted broad rules and regulations prohibiting fraud and market manipulation. The FTC is also authorized to seek fines of up to $1,180,566 per violation, subject to future adjustment for inflation. The CFTC is directed under the CEA to prevent price manipulation in the commodity, futures and swaps markets, including the energy markets. Pursuant to the Dodd-Frank Act, and other authority, the CFTC has adopted additional anti-market manipulation regulations that prohibit fraud and

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price manipulation in the commodity, futures and swaps markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,162,183 per violation, subject to future adjustment for inflation, or triple the monetary gain to the violator for each violation of the anti-market manipulation provisions of the CEA.

The distinction between federally unregulated natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and is determined by FERC on a case-by-case basis. FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by FERC, Congress or the courts. If our natural gas gathering operations or crude oil operations beyond the Epping Pipeline become subject to FERC jurisdiction under the NGA, the NGPA or the ICA, the result may materially adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, the NGPA or the ICA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by FERC.

We are subject to state and local regulation regarding the construction and operation of our gathering, treating and processing systems, as well as state ratable take statutes and regulations. Regulation of the construction and operation of our facilities may affect our ability to expand our facilities or build new facilities and such regulation may cause us to incur additional operating costs or limit the quantities of natural gas and crude oil we may gather, treat and process. Ratable take statutes and regulations generally require gatherers to take natural gas and crude oil production that may be tendered for gathering without undue discrimination. These requirements restrict our right to decide whose production we gather, treat and process. Many states have adopted complaint-based regulation of gathering, treating and processing activities, which allows producers and shippers to file complaints with state regulators in an effort to resolve access issues, rate grievances and other matters. Other state and municipal regulations do not directly apply to our business, but may nonetheless affect the availability of natural gas and crude oil for gathering, treating and processing, including state regulation of production rates, maximum daily production allowable from wells, and other activities related to drilling and operating wells. While our facilities currently are subject to limited state and local regulation, there is a risk that state or local laws will be changed or reinterpreted, which may materially affect our operations, operating costs and revenues.

Recent actions by the FERC may affect rates on Epping Pipeline and other future FERC-regulated pipelines.

On March 15, 2018, FERC announced a revised policy prohibiting FERC-jurisdictional natural gas and liquids pipelines owned by master limited partnerships from including an allowance for income taxes in the cost of service used to calculate tariff rates. Most of our pipelines are not subject to FERC regulation and so will not be affected by the revised policy statement. However, rates for interstate movements of crude oil on our Epping Pipeline in North Dakota and with any future FERC-regulated pipelines will be regulated by FERC pursuant to the Interstate Commerce Act and may be affected by the application of the revised policy statement in subsequent FERC proceedings.

FERC has not required regulated interstate oil pipelines to decrease their rates to implement the new policy. However, FERC stated that the effects of the revised policy statement must be incorporated in annual FERC financial reports made by regulated interstate oil pipelines. These reports will be used in FERC’s next five-year calculation of index rate adjustments, which will occur in 2020 and will become effective on July 1, 2021. The impact of these future proceedings on Epping Pipeline and any future FERC-regulated pipelines is uncertain at this time. Moreover, multiple parties have filed for FERC rehearing of the revised policy statement, which may trigger further changes.

Until FERC makes its next index rate adjustment, Epping Pipeline and any future FERC-regulated pipelines may face an increased risk of shipper complaints seeking FERC review of its rates. No such proceedings have occurred at this time, however, and the potential outcome of any such proceedings, should any materialize, is uncertain. Whether on complaint from a shipper or as a result of FERC's next index update, Epping Pipeline and any future FERC-regulated pipelines may be required to modify its rates, which could affect the revenues we generate with our Epping Pipeline and any future FERC-regulated pipelines. At this time, however, we do not expect any such proceedings would have a material adverse effect, but we intend to monitor FERC developments and provide updated disclosure as necessary.

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**We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.**

Our gathering, treating and processing operations are subject to stringent and complex federal, state and local environmental laws and regulations, including laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection, including, for example, the CAA, CERCLA, the CWA, the OPA, the RCRA, the Endangered Species Act and the Toxic Substances Control Act.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations or at locations currently or previously owned or operated by us. For additional information on specific laws and regulations, see the "Environmental Matters—Air Emissions" section of Item 1. Business. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and requisite permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits or regulatory authorizations, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbons and other wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering systems pass, and on which certain of our facilities are located, 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 damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in additional permitting obligations or more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance.

We may incur greater than anticipated costs and liabilities as a result of pipeline safety requirements.

The DOT, through PHMSA, has adopted and enforces safety standards and procedures applicable to our pipelines. In addition, many states, including the states in which we operate, have adopted regulations that are identical to or more restrictive than existing DOT regulations for intrastate pipelines. Among the regulations applicable to us, PHMSA requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW Midstream system is located. While the majority of our pipelines meet the DOT definition of gathering lines and are thus currently exempt from PHMSA's integrity management requirements, we also operate a limited number of pipelines that are subject to the integrity management requirements. The regulations require operators, including 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;

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- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

For additional information on PHMSA regulations relating to pipeline safety, see the "Regulation of the Natural Gas and Crude Oil Industries—Safety and Maintenance" section of Item 1. Business.

In April 2016, PHMSA proposed changes to gas pipeline safety regulations that would impose expanded assessment requirements, expand assessment and repair requirements to pipelines in areas with medium population densities (so-called "Moderate Consequence Areas"), and extend pipeline safety regulation to certain previously unregulated gas gathering pipelines. PHMSA has yet to finalize this rulemaking, however, and the timing and contents of any final rule are uncertain. In January 2017, PHMSA issued a final rule amending its pipeline safety regulations for the design, construction, testing, operation, and maintenance of pipelines transporting hazardous liquids. Among other things, the final rule would have extended certain safety-related condition reporting requirements to all hazardous liquid gathering lines and required periodic assessments of certain hazardous liquid transmission lines in non-high consequence areas. The effective date of this rulemaking is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017, pursuant to which all regulations that had been sent to the Office of the Federal Register, but not yet published, were withdrawn for further review. Accordingly, the anticipated January 2017 rulemaking was never published in the Federal Register, and the rule is not currently effective, although PHMSA could choose to reissue the rule. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. While we believe that we are in compliance with existing safety laws and regulations, increased penalties for safety violations and potential regulatory changes could have a material adverse effect on our operations, operating and maintenance expenses and revenues.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of GHGs, such as carbon dioxide and methane that may be contributing to global warming. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. For example, the revisions to the NSPS found in 40 CFR 60 subpart OOOO (and OOOOa) include GHG emission reduction requirements. However, in October 2018, the EPA published a proposed rule that would amend certain requirements of NSPS OOOOa. Among other things, the proposed rule would reduce monitoring frequencies for fugitive emissions and clarify and streamline certain other requirements. The 2016 regulation currently remains in effect.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation. For example, in January 2019, the governor of New Mexico signed an executive order that includes a goal of reducing statewide GHG emissions by at least 45% by 2030. The executive order directs the New Mexico Energy, Minerals and Natural Resources Department ("EMNRD") and the New Mexico Environment Department ("NMED") to jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions. The executive order also creates a Climate Change Task Force to evaluate and develop regulatory strategies to reach the 45% reduction

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goal. Although we cannot currently determine the effect of a potential regulatory framework developed by the ENMRD and the NMED or potential regulatory strategies that may be suggested by the Climate Change Task Force, if implemented they could be material to the business, reputation, financial condition or results of operations of our Summit Permian system.

Independent of Congress, the EPA has adopted regulations under its existing CAA authority. In 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources of GHG emissions. For additional information on EPA regulations adopted under the CAA, see the "Environmental Matters—Climate Change" section of Item 1. Business. Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global GHG emissions. The agreement entered into force in November 2016 after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. In August 2017, the United States formally documented to the United Nations its intent to withdraw from the agreement. The earliest possible effective withdrawal date from the agreement is November 2020. However, if and to the extent the United States implements this agreement, it could have a material adverse effect on our business and that of our customers.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs and could materially adversely affect demand for our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of GHG could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions, adhere to alternative energy requirements and administer and manage a GHG emissions program. While we may be able to include some or all of such increased costs in the rates we charge, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The implementation of statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

Congress adopted comprehensive financial reform legislation under the Dodd-Frank Act that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. This legislation requires the CFTC and the SEC and other regulatory authorities to promulgate certain rules and regulations, including rules and regulations relating to the regulation of certain swaps market participants, such as swap dealers, the clearing of certain swaps through central counterparties, the execution of certain swaps on designated contract markets or swap execution facilities, mandatory margin requirements for uncleared swaps, and the reporting and recordkeeping of swaps. While most of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing. Moreover, CFTC continues to refine its initial rulemakings under the Dodd-Frank Act. As a result, we cannot yet predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations could increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties.

The CFTC has proposed federal position limits on certain core futures and equivalent swaps contracts in the major energy and other markets, with exceptions for certain bona fide hedging transactions provided that various conditions are satisfied. If finalized, the position limits rule and its companion rule on aggregation among entities under common ownership or control may have an impact on our ability to hedge our exposure to certain enumerated commodities.

In 2013, the CFTC implemented final rules regarding mandatory clearing of certain classes of interest rate swaps and certain classes of index credit default swaps. Mandatory trading on designated contract markets or swap execution facilities of certain interest rate swaps and index credit default swaps also began in 2014. At this time, the CFTC has not proposed any rules designating other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also recently adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. Although we may qualify for a commercial end-user exception from the mandatory clearing, trade execution and uncleared swaps margin requirements, mandatory clearing and trade execution requirements and uncleared swaps margin requirements applicable to other market participants, such as swap dealers, may affect the cost and availability of the swaps that we use for hedging.

Under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in the following two markets: (a) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (b) financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to CFTC enforcement action and material penalties, and sanctions.

We currently enter into forward contracts with third parties to buy power and sell natural gas in an attempt to mitigate our exposure to fluctuations in the price of natural gas with respect to those volumes. The CFTC has finalized an interpretation clarifying whether certain forwards with volumetric optionality are regulated as forwards or qualify as options on commodities and therefore swaps. This interpretation may have an impact on our ability to enter into certain forwards or may impose additional requirements with respect to certain transactions.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make any transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more costly to satisfy regulatory obligations.

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

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate or if our pipelines are not properly located within the boundaries of such rights-of-way. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. If we were to be unsuccessful in renegotiating rights-of-way, we might have to relocate our facilities. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

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**We may face opposition to the development or operation of our pipelines and facilities from various groups.**

We may face opposition to the development or operation of our pipelines and facilities from environmental groups, landowners, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or other facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our unitholders and, accordingly, have a material adverse effect on our business, financial condition and results of operations.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities or energy infrastructure related projects, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

Our operations depend on the use of information technology ("IT") systems that could be the target of a cyber-attack.

Our operations depend on the use of sophisticated IT systems. Our IT systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber-attacks or information security breaches, which in turn could result in the unauthorized release and misuse of sensitive or proprietary information as well as disrupt our operations, damage our reputation or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could reduce the amount of cash otherwise available for distribution. We may be required to incur additional costs to modify or enhance our IT systems or to prevent or remediate any such attacks.

Our business is subject to complex and evolving U.S. laws and regulations regarding privacy and data protection (“data protection laws”). Many of these laws and regulations are subject to change and uncertain interpretation, and could result in claims, increased cost of operations or otherwise harm our business.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New data protection laws, including recent Colorado legislation, pose increasingly complex compliance challenges and potentially elevate our costs. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of information security breaches, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

Our ability to operate our business and implement our strategies depends on our continued ability to attract and retain highly skilled management personnel with midstream energy industry experience and competition for these persons in the midstream energy industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives

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and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

A shortage of skilled labor in the midstream energy industry could reduce employee productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The operation of gathering, treating and processing systems requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our General Partner's employees, our business and results of operations and our ability to make cash distributions to our unitholders could be materially adversely affected.

Risks Inherent in an Investment in Us

Summit Investments indirectly owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations and limited duties to us and our unitholders. Our General Partner and its affiliates have conflicts of interest with us and they may favor their own interests to the detriment of us and our unitholders.

Summit Investments controls our General Partner and has authority to appoint all of the officers and directors of our General Partner, some of whom are officers, directors or principals of Energy Capital Partners, the entity that controls Summit Investments. Although our General Partner has a duty to manage us in a manner that is in our best interests, the directors and officers of our General Partner also have a duty to manage our General Partner in a manner that is in the best interests of its owner. Conflicts of interest will arise between Summit Investments and its owners and our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of Summit Investments and its owners over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our Partnership Agreement nor any other agreement requires Summit Investments or its owners to pursue a business strategy that favors us, and the directors and officers of Summit Investments have a fiduciary duty to make these decisions in the best interests of the owners of Summit Investments, which may be contrary to our interests. Summit Investments may choose to shift the focus of their investment and growth to areas not served by our assets.
- Summit Investments is not limited in its ability to compete with us and in the future may offer business opportunities to third parties without first offering us the right to bid for them.
- Our General Partner is allowed to take into account the interests of parties other than us, such as Summit Investments and its owners, in resolving conflicts of interest.
- Our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our General Partner to us and our unitholders with contractual standards governing its duties to us and our unitholders. These contractual standards limit our General Partner's liabilities and the rights of our unitholders with respect to actions that, without the limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval.
- Our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

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- Our General Partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our General Partner.
- Our General Partner determines which costs incurred by it are reimbursable by us.
- Our General Partner may cause us to borrow funds to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distribution payments.
- Our Partnership Agreement permits us to classify up to $50.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our common units or to our General Partner in respect of the general partner interest or the IDRs.
- Our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner intends to limit its liability regarding our contractual and other obligations.
- Our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our General Partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our General Partner's IDRs without the approval of the Conflicts Committee or our unitholders. This election may result in lower distributions to our other unitholders in certain situations.

If the Equity Restructuring is consummated, the IDRs and 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest.

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

If Energy Capital Partners, the private equity firm that controls Summit Investments, consummates a transaction involving a sale or other disposition of its interests in Summit Investments, the transaction would result in a change of control of SMLP because Summit Investments indirectly owns and controls our General Partner. In addition, our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of Summit Investments to transfer all or a portion of its ownership interest in our General Partner to a third party. The owner of Summit Investments, or new members of our General Partner, as applicable, would then be in a position to replace the Board of Directors and officers of our General Partner with their own designees and thereby exert significant control over the decisions made by the Board of Directors and officers. This effectively permits a change of control without the vote or consent of the unitholders.

Our General Partner's IDRs may be transferred to a third party without unitholder consent.

Our General Partner may transfer the IDRs it owns to a third party at any time without the consent of our unitholders. If our General Partner transfers the IDRs to a third party but retains its general partner interest, our General Partner may not have the same incentive to grow our business and increase quarterly distributions to unitholders over time as it would if it had retained ownership of the IDRs. If the Equity Restructuring is consummated, the IDRs and 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest.

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**Our Sponsor is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could materially adversely affect our results of operations and cash available for distribution to our unitholders.**

Although it controls Summit Investments, our Sponsor may compete with us for investment opportunities and may own interests in entities that compete with us. Our Sponsor is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Sponsor and Summit Investments may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities.

Pursuant to the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our General Partner, its officers and directors or any of its affiliates, including Summit Investments and our Sponsor and its respective executive officers, directors and principals. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our General Partner and result in less than favorable treatment of us and our unitholders.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flows rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we report net losses for GAAP purposes and may not make cash distributions during periods when we report net income for GAAP purposes.

The market price of our common units may fluctuate significantly and, due to limited daily trading volumes, an investor could lose all or part of its investment in us.

Of the 73,390,853 common units outstanding at December 31, 2018, Summit Investments beneficially owned 25,854,581 common units and a subsidiary of Energy Capital Partners directly owned 5,915,827 common units. Upon closing of the Equity Restructuring, Summit Investments will be deemed to be the beneficial owner of the 8,750,000 common units that SMP Holdings will receive. An investor may not be able to resell its common units at or above its acquisition price. Additionally, limited liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The market price of our common units may decline and be influenced by many factors, some of which are beyond our control, including among others:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;

- the loss of a large customer;
- announcements by our customers or others regarding our customers or changes in our customers’ credit ratings, liquidity position, leverage profile and/or other financial or credit-related metrics;
- announcements by our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic and geopolitical conditions;

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- the failure of securities analysts to cover our common units or changes in financial estimates by analysts; and
- other factors described in these Risk Factors.

Our Sponsor has rights to require underwritten offerings that could limit our ability to raise capital in the public equity market.

Our Sponsor and any other unitholders that have registration rights may require us to conduct underwritten offerings of our common units. If we want to access the capital markets (debt and equity), those unitholders' ability to sell a portion of their common units could satisfy investors' demand for our common units, reduce the market price for our common units, or interfere with our financing plans, and thereby could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results timely and accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

As a publicly traded partnership, we are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, including the rules thereunder that will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with GAAP. Our efforts to develop and maintain our internal controls may not be successful and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, in addition to our limited accounting personnel and management resources, we can provide no assurance as to our or our independent registered public accounting firm's future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to implement and maintain effective internal controls over financial reporting could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

Our Partnership Agreement replaces our General Partner's fiduciary duties to unitholders with contractual standards governing its duties.

Our Partnership Agreement contains provisions that eliminate fiduciary duties to which our General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner or otherwise, free of any duties to us and our unitholders, other than the implied contractual covenant of good faith and fair dealing. This entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include, among others:

- how to allocate corporate opportunities among us and its affiliates;
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- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the Conflicts Committee;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels;

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- whether to transfer the IDRs or any units it owns to a third party; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the Partnership Agreement.

If the Equity Restructuring is consummated, the IDRs and 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Our Partnership Agreement limits the liabilities of our General Partner and the rights of our unitholders with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that limit the liability of our General Partner and the rights of our unitholders with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement provides that:

- whenever our General Partner makes a determination or takes, or declines to take, any other action in its capacity as our General Partner, our General Partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in our best interests, and will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith;
- our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our General Partner will not be in breach of its obligations under the Partnership Agreement or its duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

i. approved by the Conflicts Committee, although our General Partner is not obligated to seek such approval;
ii. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;
iii. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
iv. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner or the Conflicts Committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Conflicts Committee and the Board of Directors of our General Partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the final two subclauses above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

### Our General Partner intends to limit its liability regarding our obligations.

Our General Partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our General Partner or its assets. Our General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our General Partner. Our Partnership Agreement provides that any action taken by our General Partner to limit its liability is not a breach of our General Partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon internally generated cash flow as well as external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our Partnership Agreement, Revolving Credit Facility or Senior Notes indentures on our ability to issue additional common units, including certain other 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.

While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our Partnership Agreement can be amended with the consent of our General Partner and the approval of a majority of the outstanding common units (including common units held by affiliates of our General Partner). As of December 31, 2018, Summit Investments beneficially owned 25,854,581 common units out of 73,390,853 outstanding common units and a subsidiary of Energy Capital Partners directly owned 5,915,827 common units. Upon closing of the Equity Restructuring, Summit Investments will be deemed to be the beneficial owner of the 8,750,000 common units that SMP Holdings will receive.

Reimbursements due to our General Partner and its affiliates for expenses incurred on our behalf will reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our General Partner.

Prior to making any distribution on our common units, we will reimburse our General Partner and its affiliates, including Summit Investments, for expenses they incur and payments they make on our behalf. Under our Partnership Agreement, we will reimburse our General Partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our General Partner's employees and executive officers who provide services necessary to run our business. Our Partnership Agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses to our General Partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the MQD and the target distribution levels related to our General Partner's IDRs without the approval of the

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**Conflicts Committee or our unitholders. This election may result in lower distributions to our unitholders in certain situations.**

Our General Partner has the right, at any time when it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for such quarter), to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by our General Partner, the MQD will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset MQD), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset MQD.

In the event of a reset of target distribution levels, our General Partner will be entitled to receive the number of common units equal to that number of common units that would have entitled it to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the IDRs in the prior two quarters. Our General Partner will also be issued the number of General Partner units necessary to maintain its general partner interest in us that existed immediately prior to the reset election. We anticipate that our General Partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its IDRs and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's IDRs.

If the Equity Restructuring is consummated, the IDRs and 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest.

The New York Stock Exchange does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We have listed our common units on the New York Stock Exchange. Because we are a publicly traded partnership, the New York Stock Exchange does not require us to have, and we do not intend to have, a majority of independent directors on our General Partner's Board of Directors or to establish a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the New York Stock Exchange's shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the New York Stock Exchange corporate governance requirements.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, holders of our common units have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our General Partner or its Board of Directors. The Board of Directors of our General Partner has been chosen by Summit Investments. Furthermore, if our unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our

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operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they may not be able to remove our General Partner without its consent.

The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of December 31, 2018, Summit Investments beneficially owned 25,854,581 common units out of 73,390,853 outstanding common units, representing a voting block sufficient to prevent the other limited partners from removing our General Partner.

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

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any person or group that owns 20% or more of any class of units then outstanding cannot vote on any matter, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors of our General Partner.

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

Except in the case of the issuance of units that rank equal to or senior to the Series A Preferred Units, our Partnership Agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units that we may issue at any time without the approval of our unitholders.

We may issue additional Series A Preferred Units and any securities in parity with the Series A Preferred Units without any vote of the holders of the Series A Preferred Units (except where the cumulative distributions on the Series A Preferred Units or any parity securities are in arrears and in certain other circumstances) and without the approval of our common unitholders.

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- decreasing our existing unitholders' proportionate ownership interest in us and
- because the amount payable to holders of IDRs is based on a percentage of the total cash available for distribution, the distributions to holders of IDRs will increase even if the per-unit distribution on common units remains the same; however, if the Equity Restructuring is consummated, the IDRs and 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest.

In addition, the issuance by us of additional common units or other equity securities of equal or senior rank may have the following effects:

- decreasing the amount of cash available for distribution on each unit;
- increasing the ratio of taxable income to distributions;
- diminishing the relative voting strength of each previously outstanding unit; and
- causing the market price of the common units to decline.

Future issuances and sales of parity securities, or the perception that such issuances and sales could occur, may cause prevailing market prices for our common units and the Series A Preferred Units to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Furthermore, the payment of distributions on any additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on our common units.

**Holders of Series A Preferred Units have limited voting rights, which may be diluted.**

Although holders of the Series A Preferred Units are entitled to limited voting rights with respect to certain matters, the Series A Preferred Units generally vote separately as a class along with any other series of our parity securities that we may issue upon which like voting rights have been conferred and are exercisable. As a result, the voting rights of holders of Series A Preferred Units may be significantly diluted, and the holders of such other series of parity securities that we may issue may be able to control or significantly influence the outcome of any vote.

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

As of December 31, 2018, Summit Investments beneficially owned 25,854,581 common units out of 73,390,853 outstanding common units and a subsidiary of Energy Capital Partners directly owned 5,915,827 common units. Upon closing of the Equity Restructuring, Summit Investments will be deemed to be the beneficial owner of the 8,750,000 common units that SMP Holdings will receive. The sale of any 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 that may develop.

Our General Partner has a limited call right that may require an investor to sell its units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of our outstanding common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, an investor may be required to sell its common units at an undesirable time or price and may not receive any return on its investment. An investor may also incur a tax liability upon a sale of its units.

As of December 31, 2018, Summit Investments beneficially owned 25,854,581 common units out of 73,390,853 outstanding common units and a subsidiary of Energy Capital Partners directly owned 5,915,827 common units. As such, our General Partner and its affiliates controlled a total of 31,770,408 common units, or 43.3% of our common units outstanding as of December 31, 2018. Upon closing of the Equity Restructuring, Summit Investments will be deemed to be the beneficial owner of the 8,750,000 common units that SMP Holdings will receive.

An investor's liability may not be limited if a court finds that unitholder action constitutes control of our business.

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

- we were conducting business in a state but had not complied with that particular state's partnership statute or
- an investor's right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute control of our business.

Our Partnership Agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders’ ability to choose the judicial forum for disputes with us or our General Partner's directors, officers or other employees.

Our Partnership Agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware is the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our Partnership Agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our Partnership Agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our General Partner’s, directors, officers, or other employees, or owed by our General Partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although management believes this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our General Partner’s directors and officers. The enforceability of similar choice of forum provisions in other companies’ certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our Partnership Agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Delaware law, we may not make a distribution 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 an 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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

If an investor is not an eligible holder, it may not receive distributions or allocations of income or loss on those common units and those common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units and Series A Preferred Units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If an investor is not an eligible holder, our General Partner may elect not to make distributions or allocate income or loss on that investor's units, and it runs the risk of having its units redeemed by us at the lower of purchase price cost or the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our Series A Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

In addition, (i) prior to December 15, 2022, distributions on the Series A Preferred Units accrue and are cumulative at the rate of 9.50% per annum of $1,000, the liquidation preference of the Series A Preferred Units and (ii) on and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of $1,000 equal to the three-month LIBOR plus a spread of 7.43%. Our obligation to pay distributions on our Series A Preferred Units could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our

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obligations to the holders of the Series A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

Our Series A Preferred Units contain covenants that may limit our business flexibility.

Our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66 2⁄3% of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede our ability to take certain actions that management or the Board of Directors may consider to be in the best interests of our unitholders. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend the Partnership Agreement in any manner that would have a material adverse effect on the existing preferences, rights, powers, duties or obligations of the Series A Preferred Units. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) under certain circumstances, create or issue certain equity securities that are senior to our common units or (B) declare or pay any distribution to common unitholders out of capital surplus.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), 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 would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be material reductions in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units. This could adversely affect our financial position, results of operations and ability to make distributions to our unitholders.

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

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

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution. Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the MQD amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships.

Any modification to the U.S. federal income tax laws and interpretations could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder’s share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholder’s allocable share of our taxable income will be taxable to it, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distributions at all.

A unitholder’s share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. A unitholder’s ratio of its share of taxable income to the cash received by it may also be affected by changes in law. For instance, under the recently enacted tax reform law known as the Tax Cuts and Jobs Act (the “Tax Reform Legislation”), the net interest expense deductions of certain business entities, including us, are limited to 30% of such entity’s “adjusted taxable income,” which is generally taxable income with certain modifications. If the limit applies, a unitholder’s taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our common units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of common units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other common units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of common units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted and the cost of any IRS contest would likely reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse effect on the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS would be borne indirectly by our unitholders and our General Partner because the costs would likely reduce our cash available for distribution.

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 Reform Legislation, for taxable years beginning after December 31, 2017, our deduction for “business interest,” (including, under proposed Treasury Regulations, our deduction for distributions on our Series A Preferred Units) is limited to the sum of our business interest income and 30% of our “adjusted taxable income.” For 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 gain or loss on the disposition of our units could be more or less than expected.

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

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

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (“IRAs”), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to an organization that is exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income (“UBTI”) and will be taxable to the exempt organization as UBTI on the exempt organization’s tax return in the year the exempt organization is allocated the income. Under the Tax Reform Legislation, an exempt organization is required to independently compute its UBTI from each separate unrelated trade or business which may prevent an exempt organization from utilizing losses we allocate to the organization against the organization’s UBTI from other sources and vice versa. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

Under the Tax Reform Legislation, if a unitholder sells or otherwise disposes of a unit, the transferee is required to withhold 10.0% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the U.S. Treasury Department and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

Treatment of distributions on our Series A Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our Series A Preferred Units than the holders of our common units and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our Series A Preferred Units is uncertain. We will treat the holders of Series A Preferred Units as partners for tax purposes and will treat distributions on the Series A Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Series A Preferred Units as ordinary income. Although a holder of Series A Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions semi-annually on the 15th day of June and December through December 15, 2022, and quarterly on the 15th day of March, June, September and December thereafter. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payment attributable to the period beginning December 15th and ending December 31st will accrue to the holder of record of a Series A Preferred Unit on December 31st for such period. Otherwise, except in the case of our liquidation, the holders of Series A Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction. We will not allocate any share of its nonrecourse liabilities to the holders of Series A Preferred Units.

Although we expect that much of the income we earn is generally eligible for the 20% deduction for qualified publicly traded partnership income available under Tax Reform Legislation, under proposed Treasury Regulations, a guaranteed payment for the use of capital will not constitute an allocable or distributive share of such income. As a result, the guaranteed payment for use of capital received by holders of our Series A Preferred Units may not be eligible for the 20% deduction for qualified publicly traded partnership income.

A holder of Series A Preferred Units will be required to recognize gain or loss on a sale of units equal to the difference between the holder's amount realized and tax basis in the units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Series A Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Series A Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder to acquire such Series A Preferred Unit. Gain or loss recognized by a holder on the sale or exchange of a Series A Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Series A Preferred Units will not generally be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in the Series A Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of the Series A Preferred Units as “effectively connected income” (which will subject holders to U.S. net income taxation and possibly the branch profits tax) that are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes.

All holders of our Series A Preferred Units are urged to consult a tax advisor with respect to the consequences of owning our Series A Preferred Units.

We prorate our items of income, gain, loss and deduction for U.S, federal income tax purposes 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 prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes 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 U.S. Treasury Department adopted Treasury Regulations allowing a similar monthly simplifying convention. However, such regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method, or if new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for federal income tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their units.

We have adopted certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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**If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, the IRS (and some states) may collect any resulting taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders could be substantially reduced.**

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our General Partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If, we make payments of taxes, penalties and interest resulting from audit adjustments, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders could be substantially reduced. Additionally, we may be required to allocate an adjustment disproportionately among our unitholders, causing the publicly traded units to have different capital accounts, unless the IRS issues further guidance.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by reducing the suspended passive loss carryovers of our unitholders (without any compensation from us to such unitholders), to the extent such underpayment is attributable to a net decrease in passive activity losses allocable to certain partners. Such reduction, if approved by the IRS, will be binding on any affected unitholders.

As a result of investing in our units, our unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if the unitholders 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, our unitholders may be subject to penalties for failure to comply with those requirements. Some of the states in which we conduct business currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is the unitholder's responsibility to file all federal, state and local tax returns.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments.

Not applicable.

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Item 2. Properties.

Our gathering systems, the unconventional resource basins in which they operate, and the reportable segments in which they are reported are as follows:

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio, is included in the Utica Shale reportable segment;
- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Tioga Midstream, crude oil, produced water and associated natural gas gathering systems operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Bison Midstream, an associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Niobrara G&P, an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara and Codell shale formations in northeastern Colorado, is included in the DJ Basin reportable segment;
- Summit Permian, an associated natural gas gathering and processing system operating in the northern Delaware Basin in southeastern New Mexico, is included in the Permian Basin reportable segment;
- Grand River, a natural gas gathering and processing system operating in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah, is included in the Piceance Basin reportable segment;
- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas, is included in the Barnett Shale reportable segment; and
- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia, is included in the Marcellus Shale reportable segment.

For additional information on our midstream assets and their capacities, see Item 1. Business.

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our gathering systems and other major facilities are located are owned by us in fee title, and we believe that we have valid title to these lands. The remainder of the land on which our major facilities are located are held by us pursuant to long-term leases or easements between us and the underlying fee owner, or permits with governmental authorities. We believe that we have valid leasehold estates or fee ownership in such lands or valid permits with governmental authorities. We have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or license. We believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses with the exception of certain ordinary course encumbrances and permits with governmental entities that have been applied for, but not yet issued.

In addition, we lease various office space under leases to support our operations. Our headquarters are located in The Woodlands, Texas. In addition, we have regional corporate offices in Denver, Colorado; Atlanta, Georgia; Pittsburgh, Pennsylvania; and Dallas, Texas.

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## Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any significant legal or governmental proceedings, except as noted below. In addition, we are not aware of any significant legal or governmental proceeding contemplated to be brought against us, under the various environmental protection statutes to which we are subject, except as noted below.

The U.S. Department of Justice has issued grand jury subpoenas to Summit Investments, the Partnership, our General Partner and Meadowlark Midstream requesting certain materials related to an incident involving a produced water disposal pipeline owned by Meadowlark Midstream that resulted in a discharge of materials into the environment. On June 19, 2015, Meadowlark Midstream and Summit Investments received a complaint from the North Dakota Industrial Commission seeking approximately $2.5 million in fines and other fees related to the rupture. On March 3, 2016, the Partnership agreed to acquire, among other things, substantially all of the issued and outstanding membership interests of Meadowlark Midstream from an indirect, wholly owned subsidiary of Summit Investments in connection with the 2016 Drop Down. The Contribution Agreement executed in connection with the 2016 Drop Down contains customary representations and warranties, and Summit Investments has agreed to indemnify the Partnership with respect to certain losses, including losses associated with the above described incident. While we cannot predict the ultimate outcome of this matter with certainty, we believe at this time that it is not likely that the Partnership or our General Partner will be subject to any material liability as a result of any governmental proceeding related to the incident.

## Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Our limited partner common units, ticker symbol "SMLP," trade on the NYSE. As of February 13, 2019, there were approximately 9,555 common unitholders, including beneficial owners of common units held in street name.

On January 24, 2019, the Board of Directors of our General Partner declared a distribution of $0.575 per unit for the quarterly period ended December 31, 2018. The distribution, which totaled $45.3 million, was paid on February 14, 2019, to unitholders of record at the close of business on February 7, 2019. Beginning with the quarter ending March 31, 2019, we expect to reduce our distribution to $0.2875 per unit.

Our Cash Distribution Policy and Restrictions on Distributions

General

Our Cash Distribution Policy. Our Partnership Agreement requires us to distribute all of our available cash quarterly. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

We pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about seven days prior to such distribution date. We make the distribution on the business day immediately preceding the indicated distribution date if the distribution date falls on a holiday or non-business day.

Prior to the closing of the Equity Restructuring, our General Partner is entitled to a maximum of 2% of all distributions that we make prior to our liquidation based on their respective general partner interest. In the future, our General Partner's percentage interest in these distributions may be reduced if we issue additional units and our General Partner does not contribute a proportionate amount of capital to us to maintain its then-existing general partner interest. Pursuant to the Equity Restructuring Agreement, this 2% general partner interest will be converted into a non-economic general partner interest. For additional information, see Note 12 to the consolidated financial statements.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay any distribution except to the extent we have available cash as defined in our Partnership Agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our cash distribution policy is subject to restrictions on distributions under our Revolving Credit Facility. Our Revolving Credit Facility contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.
- Our cash distribution policy is subject to restrictions on distributions under our Series A Preferred Units. Our Series A Preferred Units contain covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.

- Our General Partner has the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those cash reserves could result in a reduction in cash distributions to our unitholders from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our General Partner in good faith will be binding on our unitholders.

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- Although our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including the provisions requiring us to distribute all of our available cash, may be amended. We can amend our Partnership Agreement with the consent of our General Partner and the approval of a majority of the outstanding common units (including common units beneficially owned by Summit Investments). As of December 31, 2018, Summit Investments, which is the ultimate owner of our General Partner, beneficially owned 25,854,581 common units and a subsidiary of Energy Capital Partners owned 5,915,827 common units. Upon closing of the Equity Restructuring, Summit Investments will be deemed to be the beneficial owner of the 8,750,000 common units that SMP Holdings will receive.
- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement.
- Under Delaware law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase.
- If and to the extent our cash available for distribution materially declines, we may elect to reduce our quarterly distribution rate to service or repay our debt or fund expansion capital expenditures.

Preferred Unit Distributions

In November 2017, we issued 300,000 Series A Preferred Units representing limited partner interests in the Partnership at a price to the public of $1,000 per unit. We used the net proceeds of $293.2 million (after deducting underwriting discounts and offering expenses) to repay outstanding borrowings under our Revolving Credit Facility.

Distributions on the Series A Preferred Units are cumulative and compounding and are payable semi-annually in arrears on the 15th day of each June and December through and including December 15, 2022, and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year (each, a “Distribution Payment Date”) to holders of record as of the close of business on the first business day of the month of the applicable Distribution Payment Date, in each case, when, as, and if declared by the General Partner out of legally available funds for such purpose.

The initial distribution rate for the Series A Preferred Units is 9.50% per annum of the $1,000 liquidation preference per Series A Preferred Unit. On and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of the liquidation preference equal to the three-month LIBOR plus a spread of 7.43%. See Note 12 for additional details.

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## Stock Performance Table

The following graph compares the cumulative total unitholder return on our common units to the cumulative total return of the S&P 500 Stock Index and the Alerian MLP Index for the five years ended December 31, 2018 by assuming $100 was invested in each investment option as of December 31, 2013. The Alerian MLP Index is the leading gauge of energy master limited partnerships, or MLPs, and is calculated using a float-adjusted, capitalization-weighted methodology.

Issuer Purchases of Equity Securities

We made no repurchases of our common units during the quarter or year ended December 31, 2018.

Sponsor Purchases of Equity Securities

Our Sponsor made no repurchases of our common units during the quarter or year ended December 31, 2018.

Equity Compensation Plans

The information relating to SMLP's equity compensation plans required by Item 5 is included in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 6. Selected Financial Data.

The selected consolidated financial data presented as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 have been derived from the consolidated financial statements of SMLP.

These financial statements reflect the results of operations of (i) Summit Utica since December 2014; (ii) Tioga Midstream since April 2014; (iii) Ohio Gathering since January 2014; and (iv) Bison Midstream, Polar and Divide, Meadowlark Midstream, Red Rock Gathering, DFW Midstream, Grand River and Mountaineer Midstream for all periods presented. Due to the common control aspect, we account for drop down transactions on an "as-if pooled" basis for the periods during which common control existed.

The following table presents selected balance sheet and other data as of the date indicated.

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| | (In thousands, except per-unit amounts) | | | | |
| Balance sheet data: | | | | | |
| Total assets | $3,020,562 | $2,894,793 | $3,115,179 | $3,164,672 | $3,242,462 |
| Total long-term debt | 1,257,731 | 1,051,192 | 1,240,301 | 1,267,270 | 1,232,207 |
| Deferred Purchase Price Obligation | 383,934 | 362,959 | 563,281 | — | — |
| Partners' capital | 1,221,224 | 1,389,669 | 1,169,673 | 1,747,299 | 1,830,678 |
| Other data: | | | | | |
| Market price per common unit | $10.05 | $20.50 | $25.15 | $18.73 | $38.00 |

The following table presents selected statements of operations and cash flows as well as other financial data for the annual periods indicated.

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| | (In thousands, except per-unit amounts) | | | | |
| Statements of operations data: | | | | | |
| Total revenues | $506,653 | $488,741 | $402,362 | $400,557 | $387,169 |
| Total costs and expenses (1) | 371,702 | 510,577 | 290,582 | 557,735 | 369,574 |
| Interest expense | 60,535 | 68,131 | 63,810 | 59,092 | 48,586 |
| Early extinguishment of debt | — | 22,039 | — | — | — |
| Deferred Purchase Price Obligation | 20,975 | (200,322) | 55,854 | — | — |
| Loss from equity method investees (2) | (10,888) | (2,223) | (30,344) | (6,563) | (16,712) |
| Net income (loss) | 42,351 | 86,050 | (38,187) | (222,228) | (47,368) |
| Earnings (loss) per limited partner unit: | | | | | |
| Common unit - basic | $0.06 | $0.99 | $(0.71) | $(3.20) | $(0.49) |
| Common unit - diluted | 0.06 | 0.98 | (0.71) | (3.20) | (0.49) |
| Subordinated unit - basic and diluted (3) | | | | (2.88) | (0.44) |
| Statements of cash flows data: | | | | | |
| Capital expenditures (other than acquisition capital expenditures) | $200,586 | $124,215 | $142,719 | $272,225 | $343,380 |
| Contributions to equity method investees | 4,924 | 25,513 | 31,582 | 86,200 | 145,131 |
| Acquisition capital expenditures (4) | — | — | 866,858 | 288,618 | 315,872 |

| | | | | | |
|---|---|---|---|---|---|
| Purchase of noncontrolling interest | 10,981 | 797 | — | — | — |
| Other financial data: | | | | | |
| Distributions declared per unit (5) | $2.300 | $2.300 | $2.300 | $2.270 | $2.040 |

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(1) Includes (i) long-lived asset impairments of $3.9 million in 2018, (ii) long-lived asset impairments of $101.9 million and contract intangible asset impairments of $85.2 million in 2017, (iii) goodwill impairments of $248.9 million and environmental remediation expenses of $21.8 million in 2015 and (iv) goodwill impairments of $54.2 million in 2014. See Notes 5, 6, 7 and 16 to the consolidated financial statements.

(2) Includes our 40% share, or $5.7 million and $1.4 million in asset impairments recognized by Ohio Gathering in December 2018 and 2017. In addition, 2018 includes our 40% share, or $2.0 million, of an estimated legal contingency. See Note 8 to the consolidated financial statements.

(3) The subordination period ended on February 16, 2016 and all 24,409,850 subordinated units converted to common units on a one-for-one basis.

(4) Reflects cash and noncash consideration, including working capital and capital expenditure adjustments paid (received), for acquisitions and/or drop downs (see Notes 12 and 17 to the consolidated financial statements).

(5) Represents distributions declared in a given period. For example, for the year ended December 31, 2018, represents the distributions paid in February 2018, in May 2018, in August 2018 and in November 2018.

The preceding tables should be read in conjunction with MD&A and the consolidated financial statements and notes thereto.

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

MD&A is intended to inform the reader about matters affecting the financial condition and results of operations of SMLP and its subsidiaries. As a result, the following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in this report. Among other things, the consolidated financial statements and the related notes include more detailed information regarding the basis of presentation for the following information. This discussion contains forward-looking statements that constitute our plans, estimates and beliefs. These forward-looking statements involve numerous risks and uncertainties, including, but not limited to, those discussed in Forward-Looking Statements. Actual results may differ materially from those contained in any forward-looking statements.

This MD&A comprises the following sections:



Overview

We are a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in the continental United States.

We classify our midstream energy infrastructure assets into two categories:

- Core Focus Areas – production basins in which we expect our gathering systems to experience greater long-term growth, driven by our customers ability to generate more favorable returns and support sustained drilling and completion activity in varying commodity price environments. In the near-term, we expect to concentrate the majority of our capital expenditures in our Core Focus Areas. Our Utica Shale, Ohio Gathering, Williston Basin, DJ Basin and Permian Basin reportable segments (as described below) comprise our Core Focus Areas.
- Legacy Areas – production basins in which we expect our gathering systems to experience relatively lower long-term growth compared to our Core Focus Areas, given that our customers require relatively higher commodity prices to support drilling and completion activities in these basins. Upstream production served by our gathering systems in our Legacy Areas is generally more mature, as compared to our Core Focus Areas, and the decline rates for volume throughput on our gathering systems in the Legacy Areas are typically lower as a result. We expect to continue to moderate our near-term capital expenditures in these Legacy Areas. Our Piceance Basin, Barnett Shale and Marcellus Shale reportable segments (as described below) comprise our Legacy Areas.

We are the owner-operator of or have significant ownership interests in the following gathering systems, which comprise our Core Focus Areas:

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;

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- Ohio Gathering, a natural gas gathering system and a condensate stabilization facility operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;
- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Tioga Midstream, a crude oil, produced water and associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Bison Midstream, an associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Niobrara G&P, an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara and Codell shale formations in northeastern Colorado; and
- Summit Permian,

We are the owner-operator of the following gathering systems, which comprise our Legacy Areas:

- Grand River, a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah;
- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia.

For additional information on our organization and systems, see Notes 1 and 4 to the consolidated financial statements.

Our financial results are driven primarily by volume throughput and expense management. We generate the majority of our revenues from the gathering, treating and processing services that we provide to our customers. A majority of the volumes that we gather, treat and/or process have a fixed-fee rate structure which enhances the stability of our cash flows by providing a revenue stream that is not subject to direct commodity price risk. We also earn revenues from (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River systems, (ii) natural gas and crude oil marketing services in and around our gathering systems, (iii) the sale of natural gas we retain from certain DFW Midstream customers and (iv) the sale of condensate we retain from our gathering services at Grand River. These additional activities, including marketing transactions comprised of buy and sell arrangements, directly expose us to fluctuations in commodity prices and accounted for approximately 27% of total revenues during the year ended December 31, 2018. These additional activities, excluding marketing transactions comprised of buy and sell arrangements, accounted for approximately 11% of total revenues during the year ended December 31, 2018. We expect our natural gas and crude oil marketing services to increase in future periods.

We also have indirect exposure to changes in commodity prices in that persistently low commodity prices may cause our customers to delay and/or cancel drilling and/or completion activities or temporarily shut-in production, which would reduce the volumes of natural gas and crude oil (and associated volumes of produced water) that we gather. If certain of our customers cancel or delay drilling and/or completion activities or temporarily shut-in production, the associated MVCs, if any, ensure that we will earn a minimum amount of revenue.

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The following table presents certain consolidated and reportable segment financial data. For additional information on our reportable segments, see the "Segment Overview for the Years Ended December 31, 2018, 2017 and 2016" section herein.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Net income (loss) | $42,351 | $86,050 | $(38,187 ) |
| Reportable segment adjusted EBITDA | | | |
| Utica Shale | $30,285 | $34,011 | $21,035 |
| Ohio Gathering | 39,969 | 41,246 | 45,602 |
| Williston Basin | 76,701 | 66,413 | 79,475 |
| DJ Basin | 7,558 | 6,624 | 3,681 |
| Permian Basin | (1,200 ) | — | — |
| Piceance Basin | 111,042 | 111,113 | 105,560 |
| Barnett Shale | 43,268 | 46,232 | 54,634 |
| Marcellus Shale | 24,267 | 23,888 | 19,203 |
| | | | |
| Net cash provided by operating activities | $227,929 | $237,832 | $230,495 |
| Acquisitions of gathering systems (1) | — | — | 866,858 |
| Capital expenditures (2) | 200,586 | 124,215 | 142,719 |
| Contributions to equity method investees | 4,924 | 25,513 | 31,582 |
| | | | |
| Distributions to common unitholders | $180,705 | $179,103 | $167,504 |
| Distributions to Series A Preferred unitholders | 28,500 | 2,375 | — |
| Issuance of senior notes | — | 500,000 | — |
| Tender and redemption of senior notes | — | (300,000) | — |
| Net borrowings (repayments) under Revolving Credit Facility | 205,000 | (387,000) | 316,000 |
| Proceeds from underwritten issuance of common units, net of costs (3) | — | — | 125,233 |
| Proceeds from issuance of Series A preferred units, net of costs (4) | — | 293,238 | — |
| Proceeds from ATM Program common unit issuances, net of costs | — | 17,078 | — |

(1) Reflects cash and noncash consideration, including working capital and capital expenditure adjustments paid (received), for acquisitions and/or drop downs (see Note 17 to the consolidated financial statements).

(2) See "Liquidity and Capital Resources" herein and Note 4 to the consolidated financial statements for additional information on capital expenditures.

(3) Reflects proceeds from underwritten primary offerings.

(4) Reflects proceeds from the issuance of Series A preferred units.

Year ended December 31, 2018. The following items are reflected in our financial results:

- In 2018, the present value of the Deferred Purchase Price Obligation increased by $21.0 million. The change was primarily due to the passage of time and an associated decrease in the discount rate, partially offset by the continued slowing and deferral of drilling and completion activities to periods outside of the DPPO measurement period (see Note 17 to the consolidated financial statements).
- Increased natural gas, NGLs and condensate sales and cost of natural gas and NGLs associated with increased marketing related activities.
- In November 2018, a subsidiary of SMLP purchased the remaining 1% ownership interest in OpCo held by a subsidiary of Summit Investments for approximately $10.9 million. As a result of this transaction, other than our investment in Ohio Gathering, all of our business activities are now conducted through wholly owned operating subsidiaries.
- During the year ended December 31, 2018, we recognized $6.0 million in gathering services and related fees from MVC shortfall adjustments. Under Topic 606, we recognize customer obligations under their MVCs as revenue and contract assets when (i) we consider it remote that the customer will utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods; (ii) the customer incurs a

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shortfall in a contract with no banking mechanism or claw back provision; (iii) the customer's banking mechanism has expired; or (iv) it is remote that the customer will use its unexercised right.

- In December 2018,

Year ended December 31, 2017. The following items are reflected in our financial results:

- In February 2017, we completed a public offering of $500.0 million principal amount of 5.75% Senior Notes. Concurrent with and following the offering, we initiated a tender offer for the outstanding 7.5% Senior Notes. All remaining 7.5% Senior Notes were redeemed on March 18, 2017, with payment made on March 20, 2017. We used the proceeds from the issuance of the 5.75% Senior Notes to (i) fund the repurchase of the outstanding $300.0 million principal amount of 7.5% Senior Notes, (ii) pay redemption and call premiums on the 7.5% Senior Notes totaling $17.9 million and (iii) pay $172.0 million of the balance outstanding under our Revolving Credit Facility.
- In March 2017, we recognized $37.7 million of gathering services and related fees revenue that had been previously deferred, and recorded on our consolidated balance sheet as deferred revenue, in connection with an MVC arrangement with a certain Williston Basin customer, for which we determined we had no further performance obligations. We include the effect of adjustments related to MVC shortfall payments in our definition of segment adjusted EBITDA. As such, the Williston Basin segment adjusted EBITDA was not impacted because the revenue recognition was offset by the associated adjustments related to MVC shortfall payments for this customer.
-
- In 2017, we updated the Deferred Purchase Price Obligation based on management's estimate of forecasted Business Adjusted EBITDA (see Note 17 to the consolidated financial statements) and capital expenditures for the 2016 Drop Down Assets. The decrease was primarily attributable to lower expected Business Adjusted EBITDA in 2018 and 2019 associated with the 2016 Drop Down Assets partially offset by lower estimated capital expenditures. The revision in estimated Business Adjusted EBITDA and estimated capital expenditures reflects a slower expected pace of drilling and completion activities from our customers, particularly in the Utica Shale in 2018 and 2019. As of December 31, 2017, we estimated the undiscounted future value of the Deferred Purchase Price Obligation to be approximately $454.4 million. As a result of revisions in these estimates, the estimated undiscounted future payment obligation decreased by $375.9 million relative to the estimate as of December 31, 2016. The revised estimates had a favorable impact on our consolidated statements of operations for the year ended December 31, 2017.
- In December 2017,

Year ended December 31, 2016. The following items are reflected in our financial results:

- In March 2016, we acquired the 2016 Drop Down Assets from a subsidiary of Summit Investments. We funded the drop down with borrowings under our Revolving Credit Facility and the execution of the Deferred Purchase Price Obligation with Summit Investments (see Notes 12 and 17 to the consolidated financial statements).
- In June 2016, an impairment loss was recognized by OCC. We recorded our 40% share of the impairment loss, or $37.8 million, in loss from equity method investees in the consolidated statements of operations.
- In September 2016, we completed an underwritten public offering of 5,500,000 common units at a price of $23.20 per unit and used the net proceeds to pay down our Revolving Credit Facility. Following the offering, our General

Partner made a capital contribution to us to maintain its approximate 2% general partner interest.

Trends and Outlook

Our business has been, and we expect our future business to continue to be, affected by the following key trends:

- Natural gas, NGL and crude oil supply and demand dynamics;
- Production from U.S. shale plays;
- Capital markets activity and cost of capital; and
- Shifts in operating costs and inflation.

Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural gas, NGL and crude oil supply and demand dynamics. Natural gas continues to be a critical component of energy supply and demand in the United States. The average spot price of natural gas increased during 2018 relative to 2017. The average daily Henry Hub Natural Gas Spot Price was $3.15 per MMBtu during 2018, compared with $2.99 per MMBtu during 2017. Henry Hub closed at $3.19 per MMBtu on December 31, 2018. Despite these modest gains, natural gas prices continue to trade at lower-than-average historical prices due in part to increased natural gas production and the amount of natural gas in storage in the continental United States. In the near term, we believe that until the supply of natural gas in storage has been reduced, natural gas prices are likely to remain constrained. Over the long term, we believe that the prospects for continued natural gas demand are favorable and will be driven primarily by global population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation.

In addition, certain of our gathering systems are directly affected by crude oil supply and demand dynamics. Crude oil prices continued to increase during 2017 and 2018, with the average daily West Texas Intermediate ("WTI") crude oil spot price increasing from an average $50.80 per barrel during 2017 to an average of $64.95 per barrel during 2018, representing a 28% increase. However, WTI closed at $45.91 per barrel on December 31, 2018 reflecting broader market concerns for global oil supply. In response to the general increase in crude oil prices, the number of active crude oil drilling rigs in the continental United States increased from 747 in December 2017 to 885 in December 2018, according to Baker Hughes. Over the next several years, we expect that crude oil prices will support continued drilling and increasing production in the Williston Basin, Permian Basin and DJ Basin.

Growth in production from U.S. shale plays. Over the past several years, natural gas production from unconventional shale resources has increased significantly due to advances in technology that allow producers to extract significant volumes of natural gas from unconventional shale plays on favorable economic terms relative to most conventional plays. In recent years, a number of producers and their joint venture partners, including large international operators, industrial manufacturers and private equity sponsors, have committed significant capital to the development of these unconventional resources, including the Piceance, Barnett, Bakken, Marcellus, Utica and Permian Basin shale plays in which we operate, and we believe that these long-term capital investments will support drilling activity in unconventional shale plays over the long term.

Rate of growth in production from U.S. shale plays. Some of our producer customers have adjusted their drilling and completion activities and schedules to manage drilling and completion costs at levels that are achievable using cash flow generated from the underlying operations. Historically, as part of a strategy to accelerate production growth, these producers would raise capital to fund drilling and completion costs in excess of the cash flows generated from their underlying assets. We expect that certain of our producers will continue to adopt and implement this revised strategy, which will likely result in a slower pace of growth in production across many of our systems relative to management's previous expectations. This dynamic is a significant contributing factor to our revision in the estimated undiscounted value of the Deferred Purchase Price Obligation as of December 31, 2018, relative to our estimate as of December 31, 2016.

Capital markets availability and cost of capital. Credit markets were volatile throughout 2018, as borrowing costs increased and investors assessed the impact of rising rates on broader economic activity. The Federal Reserve

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raised its benchmark federal-funds rate from a range of 1.25% and 1.50% in December 2017 to a range between 2.25% and 2.50% in December 2018. The Federal Reserve may continue to raise interest rates in the future, to the extent that economic growth continues. Capital markets conditions, including but not limited to availability and higher borrowing costs, could affect our ability to access the debt capital markets to the extent necessary to fund our future growth. Furthermore, market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our expansion capital expenditures and acquisition capital expenditures with the issuance of additional equity. We recently announced a planned reduction in our common unit distribution to $0.2875 per quarter, beginning with the distribution to be paid in respect of the first quarter of 2019, and this reduction may further reduce demand for our common units. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise debt capital on acceptable terms, we expect to remain competitive with respect to acquisitions and capital projects, as our peers and competitors would likely face similar circumstances.

Shifts in operating costs and inflation. Throughout most of the last five years, high levels of crude oil and natural gas exploration, development and production activities across the United States resulted in increased competition for personnel and equipment as well as higher prices for labor, supplies, equipment and other services. Beginning in 2015, this dynamic began to shift as prices for crude oil and natural gas-related services decreased in line with overall decline in demand for these goods and services. While we expect lower service-related costs in the near term, we expect that over the longer term, these costs will continue to have a high correlation to changes in the prevailing price of crude oil and natural gas.

How We Evaluate Our Operations

We conduct and report our operations in the midstream energy industry through eight reportable segments. We evaluate our business operations each reporting period to determine whether any of our operating segments in which we internally report financial information are considered significant and would require us to separately disclose certain segment financial information in our external reporting. As a result of our evaluation, during the fourth quarter of 2018, we determined that the DJ Basin natural gas gathering and processing system, previously reported within the Piceance/DJ Basins reportable segment, is expected to be a significant operating segment in future reporting periods. This determination was based on, among other things, the development of a new 60 MMcf/d processing plant that is expected to be operational in 2019, which will increase volume throughput beginning in 2019. In addition, we determined the Permian Basin natural gas gathering and processing system, which was commissioned in the fourth quarter of 2018, is expected to be a significant operating segment in future reporting periods. As such, we modified our current segments in the fourth quarter of 2018 such that the DJ Basin reportable segment includes the Niobrara G&P system and the Permian Basin reportable segment includes the Summit Permian natural gas gathering and processing system. For the year ended December 31, 2018, we have disclosed the required segment information for Niobrara G&P and Summit Permian and the periods prior have been recast to reflect this change. Our reportable segments are as follows:

- the Utica Shale, which is served by Summit Utica;
- Ohio Gathering, which includes our ownership interest in OGC and OCC;
- the Williston Basin, which is served by Polar and Divide, Tioga Midstream and Bison Midstream;
- the DJ Basin, which is served by Niobrara G&P;
- the Permian Basin, which is served by Summit Permian;

- the Piceance Basin, which is served by Grand River;
- the Barnett Shale, which is served by DFW Midstream; and
- the Marcellus Shale, which is served by Mountaineer Midstream.

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Each of our reportable segments provides midstream services in a specific geographic area. Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations (see Note 4 to the consolidated financial statements).

Our management uses a variety of financial and operational metrics to analyze our consolidated and segment performance. We view these metrics as important factors in evaluating our profitability and determining the amounts of cash distributions to pay to our unitholders. These metrics include:

- throughput volume;
- revenues;
- operation and maintenance expenses; and
- segment adjusted EBITDA.

Throughput Volume

The volume of (i) natural gas that we gather, compress, treat and/or process and (ii) crude oil and produced water that we gather depends on the level of production from natural gas or crude oil wells connected to our gathering systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity. Furthermore, because the production rate of natural gas and crude oil wells decline over time, production can only be maintained or increased by new drilling or other activity.

As a result, we must continually obtain new supplies of production to maintain or increase the throughput volume on our systems. Our ability to maintain or increase throughput volumes from existing customers and obtain new supplies of throughput is impacted by:

- successful drilling activity within our AMIs;
- the level of work-overs and recompletions of wells on existing pad sites to which our gathering systems are connected;
- the number of new pad sites in our AMIs awaiting connections;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing AMIs; and
- our ability to gather, treat and/or process production that has been released from commitments with our competitors.

We report volumes gathered for natural gas in cubic feet per day. We aggregate crude oil and produced water gathering and report volumes gathered in barrels per day.

Revenues

Our revenues are primarily attributable to the volumes that we gather, treat and/or process and the rates we charge for those services. A majority of our gathering and processing agreements are fee-based, which limits our direct exposure to fluctuations in commodity prices. We also have percent-of-proceeds arrangements under which the gathering and processing revenues that we earn correlate directly with the fluctuating price of natural gas, condensate and NGLs.

Certain of our gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. These MVCs help us generate stable revenues and serve to mitigate the financial impact associated with declining volumes.

Operation and Maintenance Expenses

We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating our assets. Direct labor costs, compression costs, ad valorem taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services comprise the most significant portion of our operation and maintenance expense. Other than utilities expense, these expenses are largely independent of volumes delivered through our gathering systems but may fluctuate depending on the activities performed during a specific period.

Segment Adjusted EBITDA

Segment adjusted EBITDA is a supplemental financial measure used by management and by external users of our financial statements such as investors, commercial banks, research analysts and others.

Segment adjusted EBITDA is used to assess:

- the ability of our assets to generate cash sufficient to make cash distributions and support our indebtedness;
- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure;
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities; and
- the financial performance of our assets without regard to (i) income or loss from equity method investees, (ii) the impact of the timing of minimum volume commitment shortfall payments under our gathering agreements or (iii) the timing of impairments or other noncash income or expense items.

Additional Information. For additional information, see the "Results of Operations" section herein and the notes to the consolidated financial statements. For information on pending accounting changes that are expected to materially impact our financial results reported in future periods, see Note 2 to the consolidated financial statements.

Results of Operations

Our financial results are recognized as follows:

Gathering services and related fees. Revenue earned from the gathering, compression, treating and processing services that we provide to our customers.

Natural gas, NGLs and condensate sales. Revenue earned from (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River systems, (ii) natural gas and crude oil marketing services in and around our gathering systems, (iii) the sale of natural gas we retain from certain DFW Midstream customers and (iv) the sale of condensate we retain from our gathering services at Grand River.

Other revenues. Revenue earned primarily from (i) certain costs for which certain of our customers have agreed to reimburse us and (ii) connection fees for customers of the Polar and Divide system.

Cost of natural gas and NGLs. The cost of natural gas and NGLs represents (i) the purchase of natural gas and NGLs associated with marketing activity surrounding certain of our natural gas and crude oil-related operations and (ii) the costs associated with the percent-of-proceeds arrangements under which we sell natural gas and NGLs purchased from certain of our customers on the Bison Midstream and Grand River systems.

Operation and maintenance. Operation and maintenance primarily comprises direct labor costs, compression costs, ad valorem taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services. These items represent the most significant portion of our operation and maintenance expense. Other than utilities expense, these expenses are largely independent of variations in throughput volumes but may fluctuate depending on the activities performed during a specific period.

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***General and administrative.*** Expenses associated with our operations that are not specifically associated with the operation and maintenance of a particular system or another cost and expense line item. These expenses largely reflect salaries, benefits and incentive compensation, professional fees, insurance and rent.

Depreciation and amortization. The depreciation of our property, plant and equipment and the amortization of our contract and right-of-way intangible assets.

Transaction costs. Financial and legal advisory costs associated with completed acquisitions and divestitures.

Other income or expense. Generally represents other items of gain or loss but may also include interest income.

Interest expense. Interest expense associated with our Revolving Credit Facility and our Senior Notes as well as amortization expense associated with debt issuance costs.

Deferred Purchase Price Obligation. Represents the change in fair value associated with the Deferred Purchase Price Obligation.

Income tax expense or benefit. Represents the expense or benefit associated with the Texas Margin Tax.

Income or loss from equity method investees. Represents the income or loss associated with our ownership interest in Ohio Gathering.

Consolidated Overview for the Years Ended December 31, 2018, 2017 and 2016

The following table presents certain consolidated data and volume throughput for the years ended December 31.

| | Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (In thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $344,616 | $394,427 | $345,961 | (13%) | 14% |
| Natural gas, NGLs and condensate sales | 134,834 | 68,459 | 35,833 | 97% | 91% |
| Other revenues | 27,203 | 25,855 | 20,568 | 5% | 26% |
| Total revenues | 506,653 | 488,741 | 402,362 | 4% | 21% |
| Costs and expenses: | | | | | |
| Cost of natural gas and NGLs | 107,661 | 57,237 | 27,421 | 88% | 109% |
| Operation and maintenance | 96,878 | 93,882 | 95,334 | 3% | (2%) |
| General and administrative | 52,877 | 54,681 | 52,410 | (3%) | 4% |
| Depreciation and amortization | 107,100 | 115,475 | 112,239 | (7%) | 3% |
| Transaction costs | — | 73 | 1,321 | * | * |
| Loss on asset sales, net | — | 527 | 93 | * | * |
| Long-lived asset impairment | 7,186 | 188,702 | 1,764 | * | * |
| Total costs and expenses | 371,702 | 510,577 | 290,582 | (27%) | 76% |
| Other (expense) income | (169 ) | 298 | 116 | * | * |
| Interest expense | (60,535 ) | (68,131 ) | (63,810 ) | (11%) | 7% |
| Early extinguishment of debt | — | (22,039 ) | — | * | * |
| Deferred Purchase Price Obligation | (20,975 ) | 200,322 | (55,854 ) | * | * |

| | | | | | |
|---|---|---|---|---|---|
| Income (loss) before income taxes and loss from equity method investees | 53,272 | 88,614 | (7,768 ) | * | * |
| Income tax expense | (33 ) | (341 ) | (75 ) | * | * |
| Loss from equity method investees | (10,888 ) | (2,223 ) | (30,344 ) | 390% | (93%) |
| Net income (loss) | $42,351 | $86,050 | $(38,187 ) | * | * |
| Volume throughput (1): | | | | | |
| Aggregate average daily throughput - natural gas (MMcf/d) | 1,673 | 1,748 | 1,528 | (4%) | 14% |
| Aggregate average daily throughput - liquids (Mbbl/d) | 94.9 | 75.2 | 88.9 | 26% | (15%) |

* Not considered meaningful

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(1) Exclusive of volume throughput for Ohio Gathering. For additional information, see the "Ohio Gathering" section herein.

Volumes – Gas. Natural gas throughput volumes decreased 75 MMcf/d during the year ended December 31, 2018, as compared to the prior year, primarily reflecting:

- a volume throughput decrease of 31 MMcf/d for the Piceance Basin segment.
- a volume throughput decrease of 28 MMcf/d for the Marcellus Shale segment.
- a volume throughput decrease of 14 MMcf/d for the Barnett Shale segment.
- a volume throughput decrease of 6 MMcf/d for the Utica Shale segment.
- a volume throughput increase of 4 MMcf/d for the DJ Basin segment.

Natural gas throughput volumes increased 220 MMcf/d during the year ended December 31, 2017, as compared to prior year, primarily reflected:

- a volume throughput increase of 179 MMcf/d for the Utica Shale segment.
- a volume throughput increase of 87 MMcf/d for the Marcellus Shale segment.
- a volume throughput decrease of 52 MMcf/d for the Barnett Shale segment.

For additional information on volumes, see the "Segment Overview for the Years Ended December 31, 2018, 2017 and 2016" section herein.

Volumes – Liquids. Crude oil and produced water throughput volumes at the Williston segment increased 19.7 Mbbl/d during the year ended December 31, 2018, as compared to the prior year, primarily reflecting well completion activity behind our Polar and Divide system in the second half of 2017 and in 2018 as well as the addition of new customers in 2017 and 2018.

Crude oil and produced water throughput volumes at the Williston segment decreased 13.7 Mbbl/d during the year ended December 31, 2017, as compared to the prior year, primarily reflecting natural production declines and decreased drilling and completion activity.

Revenues. Total revenues increased $17.9 million, during the year ended December 31, 2018, as compared to the prior year, primarily reflecting:

- a $66.4 million increase in natural gas, NGLs and condensate sales primarily attributable to increased natural gas and/or crude oil marketing activity for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.
- a $6.0 million increase from the recognition of MVC shortfall adjustments for the Barnett Shale segment under Topic 606 (see Note 3 in the consolidated financial statements).
- a $13.3 million decrease in gathering services and related fees for the Williston Basin segment due to the reclassification of amounts under certain percent-of-proceeds arrangements currently recognized on a net basis in cost of natural gas and NGLs under Topic 606 (see Note 3 in the consolidated financial statements).
- a $3.6 million decrease in gathering services and related fees for the Barnett Shale segment largely as a result of the expiration of an MVC during 2017.
- the impact of the 2017 recognition of $37.7 million of previously deferred revenue related to a certain Williston Basin customer.

Total revenues increased $86.4 million, during the year ended December 31, 2017, as compared to the prior year, primarily reflected:

- 

- the recognition of $37.7 million of previously deferred revenue related to a certain Williston Basin customer.
- the recognition of $2.6 million of business interruption recoveries for the Williston Basin segment.

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- a $22.9 million increase in natural gas, NGLs and condensate sales attributable to increased marketing activity surrounding our natural gas-related operations and the impact of higher comparative commodity pricing.
- a $14.6 million increase for the Utica Shale segment due to the ongoing development of the Summit Utica system, including the commissioning of the TPL-7 connector project in late March 2017.
- a $13.6 million increase in natural gas, NGLs and condensate sales attributable to the impact of higher comparative commodity pricing in the Williston Basin, Piceance Basin and DJ Basin segments.
- a $4.3 million increase for the Marcellus Shale segment primarily as a result of higher volumes generated by increased drilling and completion activity.
- an $8.3 million decrease for the Barnett Shale segment largely as a result of natural production declines and reduced drilling activity on the DFW Midstream system.

Gathering Services and Related Fees. Gathering services and related fees decreased $49.8 million during the year ended December 31, 2018, as compared to the prior year, primarily reflecting:

- the impact of the 2017 recognition of $37.7 million of previously deferred revenue related to a certain Williston Basin customer.
- a $13.3 million decrease in gathering services and related fees for the Williston Basin segment due to the reclassification of amounts under certain percent-of-proceeds arrangements currently recognized on a net basis in cost of natural gas and NGLs under Topic 606.
- a $3.6 million decrease in gathering services and related fees for the Barnett Shale segment largely as a result of the expiration of an MVC during 2017.
- a $6.0 million increase from the recognition of MVC shortfall adjustments for the Barnett Shale segment under Topic 606 (see Note 3 in the consolidated financial statements).

Gathering services and related fees increased $48.5 million during the year ended December 31, 2017, as compared to the prior year, primarily reflected:

- the recognition of $37.7 million of previously deferred revenue related to a certain Williston Basin customer.
- the recognition of $2.6 million of business interruption recoveries for the Williston Basin segment.
- a $14.6 million increase for the Utica Shale segment due to the ongoing development of the Summit Utica system, including the commissioning of the TPL-7 connector project in late March 2017.
- a $9.5 million decrease for the Williston Basin segment primarily due to natural production declines and reduced drilling and completion activity on the Polar and Divide system.
- a $10.6 million decrease for the Barnett Shale segment largely as a result of natural production declines and reduced drilling activity on the DFW Midstream system.

Natural Gas, NGLs and Condensate Sales. Natural gas, NGLs and condensate sales increased $66.4 million during the year ended December 31, 2018, as compared to the prior period, primarily reflecting the addition of natural gas, NGL and crude oil marketing services provided for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.

Natural gas, NGLs and condensate sales increased $32.6 million during the year ended December 31, 2017, as compared to the prior period, primarily reflecting the addition of natural gas, NGL and crude oil marketing services provided for the Piceance Basin, DJ Basin and Barnett Shale segments and the impact of higher comparative commodity pricing and throughput of NGLs on our Williston Basin, Piceance Basin and DJ Basin segments.

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***Costs and Expenses.*** Total costs and expenses decreased $138.9 million during the year ended December 31, 2018, as compared to the prior period, primarily reflecting:

- the impact of the 2017 recognition of $187.1 million of certain intangible and long-lived asset impairments relating to the Bison Midstream system in the Williston Basin segment.
- a $63.7 million increase in natural gas, NGLs and condensate purchases primarily driven by increased natural gas, NGL and crude oil marketing activity for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.
- a $3.0 million increase in operation and maintenance expense primarily due to planned compressor overhaul maintenance.
- a $13.3 million decrease in the cost of natural gas and NGLs for the Williston Basin segment due to the reclassification of amounts under certain percent-of-proceeds arrangements under Topic 606 that were previously recognized in gathering services and related fees.
- a $8.4 million decrease in depreciation and amortization primarily due to the impairment of certain intangible and long-lived assets relating to the Bison Midstream system in the Williston Basin segment recognized in the fourth quarter of 2017.

Total costs and expenses increased $220.0 million during the year ended December 31, 2017, as compared to the prior period, primarily reflected:

- the recognition of $187.1 million of certain intangible and long-lived asset impairments relating to the Bison Midstream system in the Williston Basin segment.
- a $19.3 million increase in cost of natural gas and NGLs driven by higher natural gas marketing volumes due to increased marketing activity surrounding our natural gas-related operations and the impact of higher comparative commodity pricing.
- a $9.6 million increase in cost of natural gas and NGLs primarily for the Williston Basin segment due to the impact of increasing commodity prices on the percent-of-proceeds activity for the Bison Midstream system.
- a $3.2 million increase in depreciation and amortization primarily driven by an increase in assets placed into service in the Summit Utica system.

Cost of Natural Gas and NGLs. Cost of natural gas and NGLs increased $50.4 million during the year ended December 31, 2018, as compared to the prior period, primarily reflecting:

- a $63.7 million increase in natural gas, NGLs, crude oil and condensate purchases driven by increased natural gas, NGL and crude oil marketing activity for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.
- the reclassification of $13.3 million in cost of natural gas and NGLs for the Williston Basin segment under certain percent-of-proceeds arrangements previously recognized in gathering services and related fees, which is presented net in cost of natural gas and NGLs under Topic 606.

Cost of natural gas and NGLs increased $29.8 million during the year ended December 31, 2017, as compared to the prior period, primarily reflecting:

- a $19.3 million increase in purchases associated with our natural gas and crude oil marketing services and an increase due to higher comparative commodity pricing and throughput of NGLs on our Williston Basin and Piceance Basin segments and the associated impact on (i) our percent-of-proceeds arrangements for the Bison Midstream system and (ii) our percent-of-proceeds arrangements and condensate sales for the Grand River system.

Operation and Maintenance. Operation and maintenance expense increased $3.0 million during the year ended December 31, 2018, as compared to the prior period, primarily due to an increase in planned compressor overhaul maintenance.

Operation and maintenance expense decreased $1.5 million during the year ended December 31, 2017, as compared to the prior period primarily due to a decrease in expenses that we pass through to our customers. The decrease was primarily a result of lower volume throughput in the Williston Basin and Barnett Shale segments.

General and Administrative. General and administrative expense decreased $1.8 million during the year ended December 31, 2018, as compared to the prior period, primarily reflecting a decrease in information technology expense of $1.3 million and an increase in capitalized labor of $0.7 million associated with the continued development of Summit Permian and the DJ Basin.

General and administrative expense increased $2.3 million during the year ended December 31, 2017, as compared to the prior period, primarily reflecting an increase in salaries and benefits as a result of increased headcount. For additional information, see the "Corporate and Other Overview of the Years Ended December 31, 2018, 2017 and 2016" sections herein.

Depreciation and Amortization. The decrease in depreciation and amortization expense during 2018 was primarily due to the impairment of certain intangible and long-lived assets on the Bison Midstream system in the Williston Basin segment recognized in the fourth quarter of 2017. The increase in depreciation and amortization expense during 2017 was largely driven by an increase in assets placed into service in the Summit Utica system.

Transaction Costs. Transaction costs recognized during the year ended December 31, 2016 primarily relate to financial and legal advisory costs associated with the 2016 Drop Down.

Interest Expense. The decrease in interest expense during the year ended December 31, 2018, as compared to the prior period, was as a result of (i) the tender and redemption of the $300.0 million principal 7.5% Senior Notes, (ii) the issuance of 300,000 Series A Preferred Units in November 2017 whereby the net proceeds were used to repay outstanding borrowings under our Revolving Credit Facility and (iii) a lower average outstanding balance on the Revolving Credit Facility. The decrease was partially offset by the interest associated with issuance of the $500.0 million principal 5.75% Senior Notes and an increase in the interest rate on the Revolving Credit Facility.

The increase in interest expense during the year ended December 31, 2017, as compared to the prior period, was primarily driven by the interest associated with issuance of the $500.0 million principal 5.75% Senior Notes and an increase in the interest rate on the Revolving Credit Facility. These increases were partially offset by (i) the tender and redemption of the $300.0 million principal 7.5% Senior Notes, (ii) a lower outstanding balance on the Revolving Credit Facility and (iii) the issuance of 300,000 Series A Preferred Units in November 2017 whereby the net proceeds were used to repay outstanding borrowings under our Revolving Credit Facility.

Early Extinguishment of Debt. The early extinguishment of debt recognized during 2017 was driven by the tender and redemption of the $300.0 million principal 7.5% Senior Notes.

Deferred Purchase Price Obligation. Deferred Purchase Price Obligation recognized during the year ended December 31, 2018 represents the change in present value of the estimated Remaining Consideration to be paid in connection with the 2016 Drop Down (see Notes 17 and 19 to the consolidated financial statements). The change was primarily due to the passage of time and an associated decrease in the discount rate, partially offset by the continued slowing and deferral of drilling and completion activities to periods outside of the DPPO measurement period.

In 2017, we updated the Deferred Purchase Price Obligation based on management's estimate of forecasted Business Adjusted EBITDA and capital expenditures for the 2016 Drop Down Assets. The decrease was primarily attributable to lower expected Business Adjusted EBITDA in 2018 and 2019 associated with the 2016 Drop Down Assets, partially offset by lower estimated capital expenditures. The revision in estimated Business Adjusted EBITDA and estimated capital expenditures reflects a slower expected pace of drilling and completion activities from our customers, particularly in the Utica Shale in 2018 and 2019. As of December 31, 2017, we estimated the undiscounted future value of the Deferred Purchase Price Obligation to be approximately $454.4 million. As a result of revisions in these estimates, the estimated undiscounted future payment obligation decreased by $375.9 million relative to the estimate as of December 31, 2016. The revised estimates had a favorable impact on our consolidated statements of operations for the year ended December 31, 2017.

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The Deferred Purchase Price Obligation recognized in 2016 relates to our 2016 Drop Down transaction and the issuance of the Deferred Payment in connection with the 2016 Drop Down (see Notes 2 and 17 to the consolidated financial statements).

For additional information, see the "Segment Overview for the Years Ended December 31, 2018, 2017 and 2016" and "Corporate and Other Overview for the Years Ended December 31, 2018, 2017 and 2016" sections herein and "Business – Recent Developments."

Segment Overview for the Years Ended December 31, 2018, 2017 and 2016

Utica Shale. The Utica Shale reportable segment includes the Summit Utica system. Volume throughput for our Summit Utica system follows.

| | Utica Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Average daily throughput (MMcf/d) | 359 | 365 | 186 | (2%) | 96% |

Volume throughput decreased during 2018 due to natural declines from existing wells on pad sites connected to the Summit Utica system together with temporary production curtailments associated with infill drilling and completion activity from customers on existing pad sites, partially offset by the completion of new wells during 2017 and in 2018. In addition, the TPL-7 connector project was commissioned in the first quarter of 2017 which partially offset volume declines in 2018 due to a full year of operations.

Volume throughput increased during 2017 due to the ongoing development of the system and completion of new wells during 2017. In addition, the TPL-7 connector project contributed to increased volumes.

Financial data for our Utica Shale reportable segment follows.

| | Utica Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $35,233 | $38,907 | $24,263 | (9%) | 60% |
| Total revenues | 35,233 | 38,907 | 24,263 | (9%) | 60% |
| Costs and expenses: | | | | | |
| Operation and maintenance | 4,556 | 4,487 | 2,280 | 2% | 97% |
| General and administrative | 374 | 409 | 948 | (9%) | (57%) |
| Depreciation and amortization | 7,672 | 7,009 | 4,331 | 9% | 62% |
| Loss (gain) on asset sales, net | 5 | 542 | (4) | * | * |

| | | | | | |
|---|---|---|---|---|---|
| Long-lived asset impairment | 1,440 | 878 | — | * | * |
| Total costs and expenses | 14,047 | 13,325 | 7,555 | 5% | 76% |
| Add: | | | | | |
| Depreciation and amortization | 7,672 | 7,009 | 4,331 | | |
| Adjustments related to capital reimbursement activity | (18 ) | — | — | | |
| Loss (gain) on asset sales, net | 5 | 542 | (4 ) | | |
| Long-lived asset impairment | 1,440 | 878 | — | | |
| Segment adjusted EBITDA | $30,285 | $34,011 | $21,035 | (11%) | 62% |

* Not considered meaningful

Year ended December 31, 2018. Segment adjusted EBITDA decreased $3.7 million during 2018, compared to the prior period, primarily reflecting:

- a $3.7 million decrease in gathering services and related fees from a lower gathering rate mix associated with increasing volumes from the TPL-7 connector project, which was commissioned in the first quarter of 2017, along with a decrease in volume throughput from wells that we gather from pad sites on the Summit Utica

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system and temporary production curtailments. The decrease was partially offset by an increase in volume throughput associated with new wells completed in 2017 and 2018.

Year ended December 31, 2017. Segment adjusted EBITDA increased $13.0 million during 2017, compared to the prior period, primarily reflecting:

- a $14.6 million increase in gathering services and related fees primarily due to the increase in volume throughput from completion of new wells on the system and commissioning of the TPL-7 connector project in late March 2017.
- a $2.2 million increase in operation and maintenance expense primarily due to the increase in rights-of-way maintenance, the addition of leasing compression services and increase in direct labor costs.

Other items to note:

- Depreciation and amortization increased over 2016, compared to the prior period, as a result of placing assets into service.

Ohio Gathering. The Ohio Gathering reportable segment includes OGC and OCC. We account for our investment in Ohio Gathering using the equity method. We recognize our proportionate share of earnings or loss in net income on a one-month lag based on the financial information available to us during the reporting period.

Gross volume throughput for Ohio Gathering, based on a one-month lag follows.

| | Ohio Gathering Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Average daily throughput (MMcf/d) | 769 | 766 | 865 | * | (11%) |

* Not considered meaningful

Volume throughput for the Ohio Gathering system in 2018 increased slightly over the prior period as a result of increased drilling activity from our customers during the second half of 2017 and in 2018, partially offset by natural production declines on existing wells on the system.

Volume throughput for the Ohio Gathering system decreased during 2017, compared to the prior period, primarily as a result of natural production declines and decreased drilling and completion activity. The decrease was partially offset by increased volumes associated with the installation of additional compression in the dry gas window beginning in March 2017.

Financial data for our Ohio Gathering reportable segment, based on a one-month lag follows.

| Ohio Gathering Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|
| 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| (Dollars in thousands) | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Proportional adjusted EBITDA for equity method investees | $39,969 | $41,246 | $45,602 | (3%) | (10%) |
| Segment adjusted EBITDA | $39,969 | $41,246 | $45,602 | (3%) | (10%) |

Year ended December 31, 2018. Segment adjusted EBITDA for equity method investees decreased $1.3 million during 2018, compared to the prior period, primarily as a result of higher expenses, partially offset by higher volumes at OGC and OCC.

Year ended December 31, 2017. Segment adjusted EBITDA for equity method investees decreased $4.4 million during 2017, compared to the prior period, primarily due to natural production declines and decreased drilling and completion activity, partially offset by increased volumes associated with the installation of additional compression in the dry gas window beginning in March 2017.

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Williston Basin. The Polar and Divide, Tioga Midstream and Bison Midstream systems provide our midstream services for the Williston Basin reportable segment. Volume throughput for our Williston Basin reportable segment follows.

| | Williston Basin Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Aggregate average daily throughput - natural gas (MMcf/d) | 18 | 19 | 22 | (5%) | (14%) |
| Aggregate average daily throughput - liquids (Mbbl/d) | 94.9 | 75.2 | 88.9 | 26% | (15%) |

Natural gas. Natural gas volume throughput decreased during 2018 and 2017, primarily reflecting natural production declines.

Liquids. The increase in liquids volume throughput during 2018 primarily reflected well completion activity by existing customers on our Polar and Divide system in the second half of 2017 and in 2018 as well as the addition of new customers.

The decrease in liquids volume throughput during 2017 primarily reflected natural production declines and decreased drilling and completion activity.

Financial data for our Williston Basin reportable segment follows.

| | Williston Basin Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $79,606 | $120,717 | $89,962 | (34%) | 34% |
| Natural gas, NGLs and condensate sales | 31,840 | 29,724 | 20,158 | 7% | 47% |
| Other revenues | 12,204 | 11,062 | 12,054 | 10% | (8%) |
| Total revenues | 123,650 | 161,503 | 122,174 | (23%) | 32% |
| Costs and expenses: | | | | | |
| Cost of natural gas and NGLs | 18,284 | 30,004 | 20,384 | (39%) | 47% |
| Operation and maintenance | 25,300 | 25,058 | 28,430 | 1% | (12%) |
| General and administrative | 2,089 | 2,335 | 2,576 | (11%) | (9%) |
| Depreciation and amortization | 22,642 | 33,772 | 33,676 | (33%) | * |
| Loss (gain) on asset sales, net | 63 | (22) | 88 | * | * |
| Long-lived asset impairment | 3,972 | 187,127 | 569 | * | * |
| Total costs and expenses | 72,350 | 278,274 | 85,723 | * | * |
| Add: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Depreciation and amortization | 22,642 | 33,772 | 33,676 | | |
| Adjustments related to MVC shortfall payments | — | (37,693 ) | 8,691 | | |
| Adjustments related to capital reimbursement activity | (1,276 ) | — | — | | |
| Loss (gain) on asset sales, net | 63 | (22 ) | 88 | | |
| Long-lived asset impairment | 3,972 | 187,127 | 569 | | |
| Segment adjusted EBITDA | $76,701 | $66,413 | $79,475 | 15% | (16%) |

* Not considered meaningful

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Year ended December 31, 2018. Segment adjusted EBITDA increased $10.3 million compared to the prior period primarily reflecting an increase in liquids volume throughput on our Polar and Divide system and $1.6 million in fees attributable to our Dakota Access Pipeline interconnect which was commissioned in the second quarter of 2017.

Other items to note:

- The decrease in the cost of natural gas and NGLs includes a $13.3 million reduction in expense due to the reclassification of amounts under certain percent-of-proceeds arrangements previously recognized in gathering services and related fees under Topic 606 (see Note 3 in the consolidated financial statements).
- In the fourth quarter of 2018, we impaired certain long-lived assets relating to the Tioga Midstream system in the Williston Basin (see Note 5 to the consolidated financial statements). The impairment had no impact on segment adjusted EBITDA for the year ended December 31, 2018.
- Depreciation and amortization decreased during 2018 largely as a result of the long-lived asset impairment recognized in 2017.

Year ended December 31, 2017. Segment adjusted EBITDA decreased $13.1 million during 2017, compared to the prior period primarily reflecting:

- a decrease in liquids volumes and a $3.3 million reduction in MVC shortfall payments, partially offset by $2.6 million of business interruption recoveries and the recognition of $1.6 million in gathering services and related fees relating to previously billed but unearned revenue in the second quarter of 2017.
- a benefit in 2016 from the recognition of $1.1 million in gathering services and related fees related to a settlement with a certain Williston Basin segment customer.

Other items to note:

- In the fourth quarter of 2017, we impaired certain long-lived assets and contract intangible assets relating to the Bison Midstream system in the Williston Basin (see Notes 5 and 6 to the consolidated financial statements). These impairments had no impact on segment adjusted EBITDA for the year ended December 31, 2017.
- The adjustments related to MVC shortfall payments for 2017 is primarily driven by the recognition of $37.7 million of gathering services and related fees revenue that had been previously deferred, and recorded on our consolidated balance sheet as deferred revenue, in connection with an MVC arrangement with a certain Williston Basin customer, for which we determined we had no further performance obligations. As a result, the increase in gathering services and related fees compared with the first half of 2016 was offset by the change in adjustments related to MVC shortfall payments, with no impact on segment adjusted EBITDA.

DJ Basin. The Niobrara G&P system provides midstream services for the DJ Basin reportable segment. Volume throughput for our DJ Basin reportable segment follows.

| | DJ Basin Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Aggregate average daily throughput (MMcf/d) | 17 | 13 | 8 | 31% | 63% |

Volume throughput increased during 2018 and 2017, compared to the prior periods, primarily as a result of ongoing drilling and completion activity across our service area.

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Financial data for our DJ Basin reportable segment follows.

| | DJ Basin | | | | |
|---|---|---|---|---|---|
| | Year ended December 31, | | | Percentage Change | |
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $ 11,251 | $ 8,918 | $ 6,438 | 26% | 39% |
| Natural gas, NGLs and condensate sales | 371 | 398 | — | (7%) | * |
| Other revenues | 3,672 | 2,544 | 2,001 | 44% | 27% |
| Total revenues | 15,294 | 11,860 | 8,439 | 29% | 41% |
| Costs and expenses: | | | | | |
| Cost of natural gas and NGLs | 45 | 17 | — | 165% | * |
| Operation and maintenance | 6,482 | 5,001 | 4,398 | 30% | 14% |
| General and administrative | 647 | 218 | 360 | 197% | (39%) |
| Depreciation and amortization | 3,133 | 2,636 | 2,524 | 19% | 4% |
| Loss (gain) on asset sales, net | — | 3 | (1) | * | * |
| Long-lived asset impairment | 9 | — | — | * | * |
| Total costs and expenses | 10,316 | 7,875 | 7,281 | 31% | 8% |
| Add: | | | | | |
| Depreciation and amortization | 3,133 | 2,636 | 2,524 | | |
| Adjustments related to MVC shortfall payments | — | — | — | | |
| Adjustments related to capital reimbursement activity | (562) | — | — | | |
| Loss (gain) on asset sales, net | — | 3 | (1) | | |
| Long-lived asset impairment | 9 | — | — | | |
| Segment adjusted EBITDA | $ 7,558 | $ 6,624 | $ 3,681 | 14% | 80% |

* Not considered meaningful

Year ended December 31, 2018. Segment adjusted EBITDA increased $0.9 million during 2018, compared to the prior period, primarily reflecting:

- an increase in gathering services and related fees primarily as a result of volume growth from ongoing drilling and completion activity.
- a $1.5 million increase in operation and maintenance expense primarily due to $1.1 million of higher electricity expenses we pass through to certain customers (which is also included in the increase in Other revenues in the table above) in addition to higher operation and maintenance costs to support volume growth.

Year ended December 31, 2017. Segment adjusted EBITDA increased $2.9 million during 2017, compared to the prior period, primarily reflecting:

- 

an increase in gathering services and related fees primarily as a result of volume growth from ongoing drilling and completion activity.

Permian Basin. The Summit Permian system provides our midstream services for the Permian Basin reportable segment.

Average daily volume throughput during the year ended December 31, 2018 for the Permian Basin reportable segment totaled 1 MMcf/d.

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Financial data for our Permian Basin reportable segment follows.

| | Permian Basin Year ended December 31, 2018 (In thousands) |
|---|---|
| Revenues: | |
| Gathering services and related fees | $ 115 |
| Natural gas, NGLs and condensate sales | 843 |
| Total revenues | 958 |
| Costs and expenses: | |
| Cost of natural gas and NGLs | 1,569 |
| Operation and maintenance | 428 |
| General and administrative | 161 |
| Depreciation and amortization | 243 |
| Long-lived asset impairment | 761 |
| Total costs and expenses | 3,162 |
| Add: | |
| Depreciation and amortization | 243 |
| Long-lived asset impairment | 761 |
| Segment adjusted EBITDA | $ (1,200 ) |

Year ended December 31, 2018. Segment adjusted EBITDA totaled ($1.2) million primarily reflecting less than one month's volume throughput of the Summit Permian natural gas gathering and processing system commissioned in December 2018 as well as operational and general and administrative expenses incurred during the year.

Piceance Basin. The Grand River system provides midstream services for the Piceance Basin reportable segment. Volume throughput for our Piceance Basin reportable segment follows.

| | Piceance Basin Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Aggregate average daily throughput (MMcf/d) | 551 | 582 | 578 | (5%) | 1% |

Volume throughput decreased during 2018, compared to the prior period, as a result of natural production declines, partially offset by drilling and completion activity that occurred across our service area during the second half of 2017 and through the third quarter of 2018.

Volume throughput increased during 2017, compared to the prior period, despite the continued suspended drilling activities by one of Grand River's key customers, primarily as a result of ongoing drilling and completion activity by other customers across our gathering footprint.

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Financial data for our Piceance Basin reportable segment follows.

| | Piceance Basin Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $135,810 | $136,834 | $126,998 | (1%) | 8% |
| Natural gas, NGLs and condensate sales | 14,800 | 13,452 | 9,808 | 10% | 37% |
| Other revenues | 4,909 | 4,607 | 4,658 | 7% | (1%) |
| Total revenues | 155,519 | 154,893 | 141,464 | 0% | 9% |
| Costs and expenses: | | | | | |
| Cost of natural gas and NGLs | 9,591 | 7,952 | 7,096 | 21% | 12% |
| Operation and maintenance | 33,947 | 30,143 | 29,126 | 13% | 3% |
| General and administrative | 1,168 | 2,617 | 2,653 | (55%) | (1%) |
| Depreciation and amortization | 46,919 | 46,289 | 46,616 | 1% | (1%) |
| Loss on asset sales, net | — | — | 10 | * | * |
| Long-lived asset impairment | 1,004 | 697 | — | 44% | * |
| Total costs and expenses | 92,629 | 87,698 | 85,501 | 6% | 3% |
| Add: | | | | | |
| Depreciation and amortization | 46,919 | 46,289 | 46,616 | | |
| Adjustments related to MVC shortfall payments | 10 | (3,068) | 2,971 | | |
| Adjustments related to capital reimbursement activity | 219 | — | — | | |
| Loss on asset sales, net | — | — | 10 | | |
| Long-lived asset impairment | 1,004 | 697 | — | | |
| Segment adjusted EBITDA | $111,042 | $111,113 | $105,560 | (0%) | 5% |

* Not considered meaningful

Year ended December 31, 2018. Segment adjusted EBITDA decreased $0.1 million during 2018, compared to the prior period, primarily reflecting:

- a $3.8 million increase in operation and maintenance expense primarily due to planned compressor overhaul maintenance costs during the period.
- a $1.5 million decrease in general and administrative expenses.
- a $2.3 million increase, after taking into account the adjustments related to MVC shortfall payments and adjustments related to capital reimbursement activity, in gathering services and related fees primarily as a result of the drilling and completion activity that occurred across our service area by other customers during the second half of 2017 and through the third quarter of 2018, and a $1.0 million MVC shortfall payment received from a customer in 2018 that did not occur in 2017, partially offset by natural production declines.

Year ended December 31, 2017. Segment adjusted EBITDA increased $5.6 million during 2017, compared to the prior period, primarily reflecting:

- a $3.8 million increase in gathering services and related fees, after taking into account the adjustments related to MVC shortfall payments, primarily as a result of volume growth from ongoing drilling and completion activity in addition to a favorable rate mix with certain customers.

Barnett Shale. The DFW Midstream system provides our midstream services for the Barnett Shale reportable segment.

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Volume throughput for our Barnett Shale reportable segment follows.

| | Barnett Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Average daily throughput (MMcf/d) | 253 | 267 | 319 | (5%) | (16%) |

Volume throughput declined during 2018 reflecting natural production declines, partially offset by new volumes from completion activity during the fourth quarter of 2017, first quarter of 2018 and the fourth quarter of 2018.

Volume throughput declined during 2017 as a result of seven wells being commissioned behind the DFW gathering system in the fourth quarter of 2017, as compared to the higher drilling and completion activities throughout 2016.

Financial data for our Barnett Shale reportable segment follows.

| | Barnett Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $59,030 | $61,622 | $72,234 | (4%) | (15%) |
| Natural gas, NGLs and condensate sales | 2,523 | 1,946 | 5,867 | 30% | (67%) |
| Other revenues (1) | 6,712 | 8,099 | 1,855 | (17%) | * |
| Total revenues | 68,265 | 71,667 | 79,956 | (5%) | (10%) |
| Costs and expenses: | | | | | |
| Operation and maintenance | 21,358 | 23,074 | 24,594 | (7%) | (6%) |
| General and administrative | 971 | 1,146 | 1,088 | (15%) | 5% |
| Depreciation and amortization | 15,658 | 15,604 | 15,671 | 0% | (0%) |
| (Gain) loss on asset sales, net | (68) | 4 | — | * | * |
| Long-lived asset impairment | — | — | 1,195 | * | * |
| Total costs and expenses | 37,919 | 39,828 | 42,548 | (5%) | (6%) |
| Add: | | | | | |
| Depreciation and amortization | 15,325 | 15,001 | 16,093 | | |
| Adjustments related to MVC shortfall payments | (3,642) | (612) | (62) | | |
| Adjustments related to capital reimbursement activity | 1,307 | — | — | | |
| (Gain) loss on asset sales, net | (68) | 4 | — | | |
| Long-lived asset impairment | — | — | 1,195 | | |
| Segment adjusted EBITDA | $43,268 | $46,232 | $54,634 | (6%) | (15%) |

*Not considered meaningful

(1) Includes the amortization expense associated with our favorable and unfavorable gas gathering contracts as reported in other revenues.

Year ended December 31, 2018. Segment adjusted EBITDA decreased $3.0 million during 2018, compared to the prior period, primarily reflecting:

- a $4.3 million decrease, after taking into account the adjustments related to MVC shortfall payments and adjustments related to capital reimbursement activity, in gathering services and related fees associated with the expiration of MVCs during 2017 of $3.6 million in addition to lower volume throughput.
- a $1.7 million decrease in operation and maintenance expense primarily from $1.3 million of lower electricity expenses associated with lower volume throughput and a decrease in tax expenses.

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Year ended December 31, 2017. Segment adjusted EBITDA decreased $8.4 million during 2017, compared to the prior period, primarily reflecting:

- a $10.6 million decrease in gathering services and related fees largely as a result of natural production declines and reduced drilling and completion activity.
- a $6.2 million increase in other revenues, partially offset by a $3.9 million decrease in natural gas, NGLs, and condensate sales, primarily due to electricity expense reimbursements that we began passing through to certain customers beginning in the fourth quarter of 2016.

Marcellus Shale. The Mountaineer Midstream system provides our midstream services for the Marcellus Shale reportable segment.

Volume throughput for the Marcellus Shale reportable segment follows.

| | Marcellus Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| Average daily throughput (MMcf/d) | 474 | 502 | 415 | (6%) | 21% |

Volume throughput decreased during 2018, compared to the prior period, primarily due to natural production declines. These declines were partially offset by volumes generated by the completion, in the second half of 2017 and first quarter of 2018, of a number of drilled but uncompleted ("DUC") wells.

Volume throughput increased during 2017, compared to the prior period, primarily due to the completion, in the second and fourth quarter of 2017, of DUCs that had been deferred since the third quarter of 2015. Volume throughput was also no longer impacted by repairs on a downstream third-party NGL pipeline that occurred during 2016.

Financial data for our Marcellus Shale reportable segment follows.

| | Marcellus Shale Year ended December 31, | | | Percentage Change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Gathering services and related fees | $29,573 | $30,394 | $26,111 | (3%) | 16% |
| Total revenues | 29,573 | 30,394 | 26,111 | (3%) | 16% |
| Costs and expenses: | | | | | |
| Operation and maintenance | 4,813 | 6,057 | 6,506 | (21%) | (7%) |
| General and administrative | 397 | 449 | 402 | (12%) | 12% |
| Depreciation and amortization | 9,090 | 9,047 | 8,841 | 0% | 2% |
| Total costs and expenses | 14,300 | 15,553 | 15,749 | (8%) | (1%) |
| Add: | | | | | |
| Depreciation and amortization | 9,090 | 9,047 | 8,841 | | |
| Adjustments related to capital | (96 ) | — | — | | |

| | | | | | |
|---|---|---|---|---|---|
| reimbursement activity | | | | | |
| Segment adjusted EBITDA | $24,267 | $23,888 | $19,203 | 2% | 24% |

Year ended December 31, 2018. Segment adjusted EBITDA increased $0.4 million during 2017, compared to the prior period, primarily reflecting:

- a $1.2 million decrease in operation and maintenance expense primarily due to declines in expenses for repairs to right-of-way of $0.9 million and lower property taxes of $0.7 million during the period.
- a $0.8 million decrease in gathering services and related fees as a result of volume declines.

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Year ended December 31, 2017. Segment adjusted EBITDA increased $4.7 million during 2017, compared to the prior period, primarily reflecting:

- a $4.3 million increase in gathering services and related fees primarily as a result of higher volumes generated by increased drilling and completion activity.
- a $0.4 million decrease in operation and maintenance expense primarily as a result of higher expenses incurred in 2016 associated with repairs to rights-of-way.

Corporate and Other Overview for the Years Ended December 31, 2018, 2017 and 2016

Corporate and Other represents those results that are not specifically attributable to a reportable segment or that have not been allocated to our reportable segments, including certain general and administrative expense items, natural gas and crude oil marketing services, transaction costs, interest expense, early extinguishment of debt and a change in the Deferred Purchase Price Obligation fair value.

| | Corporate and Other | | | | |
|---|---|---|---|---|---|
| | Year ended December 31, | | | Percentage Change | |
| | 2018 | 2017 | 2016 | 2018 v. 2017 | 2017 v. 2016 |
| | (Dollars in thousands) | | | | |
| Revenues: | | | | | |
| Total revenues | $78,161 | $19,517 | $(45) | * | * |
| Costs and expenses: | | | | | |
| Cost of natural gas and NGLs | 78,172 | 19,264 | (45) | * | * |
| General and administrative | 47,070 | 47,507 | 44,369 | (1%) | 7% |
| Interest expense | 60,535 | 68,131 | 63,810 | (11%) | 7% |
| Early extinguishment of debt (1) | — | 22,039 | — | * | * |
| Deferred Purchase Price Obligation | 20,975 | (200,322) | 55,854 | * | * |

* Not considered meaningful

(1) Early extinguishment of debt includes $17.9 million paid for redemption and call premiums, as well as $4.1 million of unamortized debt issuance costs which were written off in connection with the repurchase of the outstanding $300.0 million 7.5% Senior Notes in the first quarter of 2017.

Total Revenues. Total revenues attributable to Corporate and Other was due to natural gas, NGL and crude oil marketing services activity (primarily natural gas sales) for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.

Cost of Natural Gas and NGLs. Cost of natural gas and NGLs attributable to Corporate and Other increased due to natural gas, NGL and crude oil marketing services activity (primarily natural gas sales) for the Piceance Basin, DJ Basin, Barnett Shale and Williston Basin segments.

General and Administrative. General and administrative expense decreased during the year ended December 31, 2017, as compared to the prior period, primarily reflecting reductions in information technology costs.

Interest Expense. Interest expense decreased $7.6 million compared to prior period as a result of (i) the tender and redemption of the $300.0 million principal 7.5% Senior Notes, (ii) the issuance of 300,000 Series A Preferred Units in

November 2017 whereby the net proceeds were used to repay outstanding borrowings under our Revolving Credit Facility and (iii) a lower average outstanding balance on the Revolving Credit Facility. The decrease was partially offset by the interest associated with issuance of the $500.0 million principal 5.75% Senior Notes and an increase in the interest rate on the Revolving Credit Facility.

The increase in interest expense during the year ended December 31, 2017, as compared to the prior period, was primarily driven by the interest associated with issuance of the $500.0 million principal 5.75% Senior Notes and an increase in the interest rate on the Revolving Credit Facility. These increases were partially offset by (i) the tender and redemption of the $300.0 million principal 7.5% Senior Notes, (ii) a lower outstanding balance on the Revolving Credit Facility and (iii) the issuance of 300,000 Series A Preferred Units in November 2017 whereby the net proceeds were used to repay outstanding borrowings under our Revolving Credit Facility.

Early Extinguishment of Debt. The early extinguishment of debt recognized during the year ended December 31, 2017 was driven by the tender and redemption of the $300.0 million principal amount of 7.5% Senior Notes.

Deferred Purchase Price Obligation. Deferred Purchase Price Obligation recognized during the year ended December 31, 2018 represents the change in present value of the estimated Remaining Consideration to be paid in connection with the 2016 Drop Down (see Notes 17 and 19 to the consolidated financial statements). The change was primarily due to the passage of time and an associated decrease in the discount rate, partially offset by the continued slowing and deferral of drilling and completion activities to periods outside of the DPPO measurement period.

In 2017, we updated the Deferred Purchase Price Obligation based on management's estimate of forecasted Business Adjusted EBITDA and capital expenditures for the 2016 Drop Down Assets. The decrease was primarily attributable to lower expected Business Adjusted EBITDA in 2018 and 2019 associated with the 2016 Drop Down Assets partially offset by lower estimated capital expenditures. The revision in estimated Business Adjusted EBITDA and estimated capital expenditures reflects a slower expected pace of drilling and completion activities from our customers, particularly in the Utica Shale in 2018 and 2019. As of December 31, 2017, we estimated the undiscounted future value of the Deferred Purchase Price Obligation to be approximately $454.4 million. As a result of revisions in these estimates, the estimated undiscounted future payment obligation decreased by $375.9 million relative to the estimate as of December 31, 2016. The revised estimates had a favorable impact on our consolidated statements of operations for the year ended December 31, 2017 (see Notes 2 and 17 to the consolidated financial statements).

Liquidity and Capital Resources

Based on the terms of our Partnership Agreement, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect to fund future capital expenditures from cash and cash equivalents on hand, cash flows generated from our operations, borrowings under our Revolving Credit Facility and future issuances of equity and debt instruments.

Capital Markets Activity

July 2017 Shelf Registration Statement. In July 2017, we filed the 2017 SRS with the SEC to issue an indeterminate amount of debt, equity securities and guarantees. In November 2017, we filed a post-effective amendment to the 2017 SRS with the SEC to register, in addition to the classes of securities originally registered, an indeterminate amount of preferred units representing limited partner interests in the Partnership. The 2017 SRS expires in July 2020. However, we are no longer a well-known seasoned issuer and are therefore not able to use the 2017 SRS.

The following transaction was executed pursuant thereto:

•

November 2016 Shelf Registration Statement. In October 2016, we filed the 2016 SRS and in November 2016, the SEC declared it effective. The following transactions have been executed pursuant thereto:

• In February 2017, we completed a secondary public offering of 4,000,000 SMLP common units held by a subsidiary of Summit Investments in accordance with our obligations under our Partnership Agreement. We did not receive any proceeds from this secondary offering.

- In February 2017, we executed a new equity distribution agreement and filed a prospectus supplement with the SEC for the issuance and sale from time to time of SMLP common units having an aggregate offering price of up to $150.0 million. These sales are made (i) pursuant to the terms of the equity distribution agreement between us and the sales agents named therein and (ii) by means of ordinary brokers' transactions at market prices, in block transactions or as otherwise agreed between us and the sales agents. Sales of our common units may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined by SEC rules. During the year ended December 31, 2018, we did not issue any units under the ATM Program. During the year ended December 31, 2017, we issued 763,548 units under the ATM Program for aggregate gross proceeds of $17.7 million, and paid approximately $0.2 million as compensation to the sales agents pursuant to the terms of the equity distribution agreement. Our General Partner made capital contributions to maintain its approximate 2% General Partner interest in SMLP. Following the effectiveness of the new ATM registration statement and after taking into account the aggregate sales price of common units sold under the ATM Program through December 31, 2018, we have the capacity to issue additional common units under the ATM Program up to an aggregate $132.3 million.

Following the February 2017 secondary offering, we can issue up to $1.50 billion of debt and equity securities in primary offerings and a total of 32,701,230 common units held by (i) a subsidiary of Summit Investments and (ii) affiliates of our Sponsor pursuant to the 2016 SRS. The 2016 SRS expires in November 2019.

July 2014 Shelf Registration Statement. In July 2014, we filed the 2014 SRS with the SEC to issue an indeterminate amount of debt and equity securities and shortly thereafter completed a public offering of $300.0 million aggregate principal 5.5% senior unsecured notes due 2022. We used the proceeds to repay a portion of the then-outstanding borrowings under our Revolving Credit Facility.

On February 8, 2017, we amended the 2014 SRS to include additional guarantor subsidiaries and completed a public offering of $500.0 million principal 5.75% senior unsecured notes due 2025. Concurrent therewith, we made a tender offer to purchase all the outstanding 7.5% Senior Notes. The tender offer expired on February 14, 2017 with $276.9 million validly tendered. On February 16, 2017, we issued a notice of redemption for the 7.5% Senior Notes that remained outstanding subsequent to the tender offer. The remaining 7.5% Senior Notes were redeemed on March 18, 2017, with payment made on March 20, 2017. We used the proceeds from the issuance of the 5.75% Senior Notes to (i) fund the repurchase of the outstanding $300.0 million principal 7.5% Senior Notes, (ii) pay redemption and call premiums on the 7.5% Senior Notes totaling $17.9 million and (iii) pay $172.0 million of the balance outstanding under our Revolving Credit Facility.

For additional information, see Notes 10 and 12 to the consolidated financial statements.

Debt

Revolving Credit Facility. We have a $1.25 billion senior secured Revolving Credit Facility. On May 26, 2017, Summit Holdings closed on the Third Amended and Restated Credit Agreement which extended the maturity from November 2018 to May 2022 (see Note 10 to the consolidated financial statements). As of December 31, 2018, the outstanding balance of the Revolving Credit Facility was $466.0 million and the unused portion totaled $784.0 million. There were no defaults or events of default during 2018, and as of December 31, 2018, we were in compliance with the financial covenants in the Revolving Credit Facility.

Senior Notes. In June 2013, the Co-Issuers co-issued the 7.5% Senior Notes, and in July 2014, the Co-Issuers co-issued the 5.5% Senior Notes. In February 2017, the Co-Issuers co-issued the 5.75% Senior Notes. The 7.5% Senior Notes were tendered and redeemed during the first quarter of 2017. There were no defaults or events of default during 2018 on any series of senior notes.

For additional information on our long-term debt, see Notes 10 and 18 to the consolidated financial statements.

Deferred Purchase Price Obligation

In March 2016, we entered into an agreement with a subsidiary of Summit Investments to fund a portion of the 2016 Drop Down whereby we have recognized the Deferred Purchase Price Obligation (see Note 17 to the consolidated financial statements and “Business – Recent Developments”).

**Cash Flows**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Net cash provided by operating activities | $227,929 | $237,832 | $230,495 |
| Net cash used in investing activities | (216,279) | (148,683) | (534,126) |
| Net cash (used in) provided by financing activities | (8,735) | (95,147) | 289,266 |
| Net change in cash and cash equivalents | $2,915 | $(5,998) | $(14,365) |

The components of the net change in cash and cash equivalents were as follows:

Operating activities. Cash flows from operating activities for the year ended December 31, 2018, primarily reflected:

- a $6.8 million decrease in cash interest payments due to the extinguishment of the 7.5% Senior Notes in the first quarter of 2017;
- a decrease in distributions from equity method investees; and
- other changes in working capital.

Cash flows from operating activities for the year ended December 31, 2017, primarily reflected:

- increase of cash receipts due to higher revenues and associated customer payments;
- an $8.5 million increase in cash interest payments; and
- a $4.8 million decrease in distributions from Ohio Gathering.

Investing activities. Details of cash flows from investing activities follow.

Cash flows used in investing activities during the year ended December 31, 2018 primarily reflected:

- $200.6 million of capital expenditures primarily attributable to the ongoing development of the Permian Basin of $83.8 million as well as the continued development in the DJ Basin of $64.9 million, and the Williston Basin of $25.2 million;
- a $10.9 million purchase of a noncontrolling interest; and
- $4.9 million of capital contributions to Ohio Gathering.

Cash flows used in investing activities during the year ended December 31, 2017 primarily reflected:

- $124.2 million of capital expenditures primarily attributable to the ongoing development of the Summit Permian and Summit Utica systems as well as the continued development in the Williston Basin, Piceance Basin and DJ Basin segments; and
- $25.5 million of capital contributions to Ohio Gathering.

Cash flows used in investing activities during the year ended December 31, 2016 primarily reflected:

- $359.4 million consideration paid and recognized in connection with the 2016 Drop Down;
- $142.7 million of capital expenditures primarily attributable to the ongoing expansion of the 2016 Drop Down Assets and the Polar and Divide system; and
- $31.6 million of capital contributions to Ohio Gathering.

Financing activities. Details of cash flows from financing activities follow.

Cash flows used in financing activities during the year ended December 31, 2018 primarily reflected:

- $209.2 million of distributions paid; and
- $205.0 million of net borrowings under our Revolving Credit Facility.

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Cash flows provided by financing activities during the year ended December 31, 2017 primarily reflected:

- $300.0 million paid for the repurchase of the outstanding 7.5% Senior Notes;
- $387.0 million of net repayments under our Revolving Credit Facility;
- $181.5 million of distributions paid;
- $17.9 million paid for the redemption and call premiums on the 7.5% Senior Notes;
- $500.0 million of borrowings from the issuance of 5.75% Senior Notes; and
- $293.2 million of net proceeds from the issuance of Series A Preferred units in November 2017.

Cash flows provided by financing activities during the year ended December 31, 2016 primarily reflected:

- $316.0 million of net borrowings under our Revolving Credit Facility, which included $360.0 million of borrowings to fund the 2016 Drop Down and reflected a repayment in September 2016 with funds from the issuance of common units noted below;
- $167.5 million of distributions paid in 2016; and
- $125.2 million of net proceeds from the issuance of common units in September 2016.

Contractual Obligations Update

The table below summarizes our contractual obligations as of December 31, 2018.

| | Total | Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
|---|---|---|---|---|---|
| | (In thousands) | | | | |
| Long-term debt and interest payments (1) | $1,610,924 | $72,610 | $145,220 | $849,969 | $543,125 |
| Deferred Purchase Price Obligation (2) | 423,928 | — | 423,928 | — | — |
| Purchase obligations (3) | 57,167 | 57,167 | — | — | — |
| Operating leases (4) | 6,201 | 3,133 | 1,568 | 879 | 621 |
| Total contractual obligations | $2,098,220 | $132,910 | $570,716 | $850,848 | $543,746 |

(1) For the purpose of calculating future interest on the Revolving Credit Facility, assumes no change in balance or rate from December 31, 2018. Includes a 0.50% commitment fee on the unused portion of the Revolving Credit Facility. See Note 10 to the consolidated financial statements.

(2) See Notes 17 and 19 to the consolidated financial statements and “Business – Recent Developments”.

(3) Represents agreements to purchase goods or services that are enforceable and legally binding.

(4) See Item 2. Properties and Note 16 to the consolidated financial statements.

In March 2016, we borrowed $360.0 million under our Revolving Credit Facility and recognized a liability of $507.4 million for the Deferred Purchase Price Obligation, both in connection with the 2016 Drop Down. The Deferred Purchase Price Obligation is due no later than December 31, 2020 and as of December 31, 2018, was expected to be $423.9 million based on information available as of December 31, 2018. Upon consummation of the Amendment and the $100 million prepayment of the Deferred Purchase Price Obligation, the Remaining Consideration under the Deferred Purchase Price Obligation will be reduced to $303.5 million, which will be payable by the Partnership in one or more payments over the period from March 1, 2020 through December 31, 2020, payable in (i) cash, (ii) the Partnership's common units or (iii) a combination of cash and the Partnership's common units, at the discretion of the Partnership. No less than 50% of the Remaining Consideration shall be paid on or before June 30, 2020 and interest shall accrue at a rate of 8% per annum on any portion of the Remaining Consideration that remains unpaid after March 31, 2020. See Note 19 to the consolidated financial statements for additional details.

In February 2017, we issued $500.0 million principal of 5.75% senior, unsecured notes due 2025. We used the proceeds from the issuance of the 5.75% Senior Notes to (i) fund the repurchase of the outstanding $300.0 million principal 7.5% Senior Notes, (ii) pay redemption and call premiums on the 7.5% Senior Notes totaling $17.9 million and (iii) pay $172.0 million of the balance outstanding under our Revolving Credit Facility.

**Capital Requirements**

Our ability to grow, or even maintain current, cash distributions depends, in part, on our ability to capitalize on organic growth opportunities and make acquisitions that increase the amount of cash generated from our operations on a per-unit basis, along with other factors.

Developing, owning and operating midstream energy infrastructure assets requires significant investment in the maintenance of existing gathering systems and the construction and development of new gathering systems and other midstream assets and facilities.

For the year ended December 31, 2018, cash paid for capital expenditures totaled $200.6 million, compared with $124.2 million for the year ended December 31, 2017 and $142.7 million for the year ended December 31, 2016 (see Note 4 to the consolidated financial statements). Maintenance capital expenditures totaled $21.4 million for the year ended December 31, 2018, compared with $15.6 million for the year ended December 31, 2017 and $17.7 million for the year ended December 31, 2016. For the year ended December 31, 2018, contributions to equity method investees totaled $4.9 million, compared with $25.5 million for the year ended December 31, 2017 and $31.6 million for the year ended December 31, 2016 (see Note 8 to the consolidated financial statements). The year-over-year increase in cash paid for capital expenditures primarily reflected the expansion of our existing gathering and processing complex in the DJ Basin with the addition of a new 60 MMcf/d cryogenic processing plant in addition to the development of our new associated natural gas gathering and processing system in the Permian Basin.

The acquisition component and greenfield development projects of our growth strategy has required and will continue to require significant expenditures by us. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We intend to continue to pursue accretive acquisitions of midstream assets from third parties. However, their size, timing and/or contribution to our operations and financial results cannot be reasonably estimated. Furthermore, there are a number of risks and uncertainties that could cause our current expectations to change, including, but not limited to, (i) the ability to reach agreement with third parties; (ii) prevailing conditions and outlook in the natural gas, crude oil and natural gas liquids industries and markets and (iii) our ability to obtain financing from commercial banks, the capital markets, or other sources such as our Sponsor and Summit Investments, among other factors.

We rely primarily on internally generated cash flow as well as external financing sources, including commercial bank borrowings and the issuance of debt, equity and preferred equity securities, to fund our capital expenditures. We believe that our Revolving Credit Facility, together with internally generated cash flow and financial support from our Sponsor and/or access to new debt or equity capital markets, will be adequate to finance our growth objectives for the foreseeable future without adversely impacting our liquidity or our ability to make quarterly cash distributions to our unitholders.

Credit and Counterparty Concentration Risks

We examine the creditworthiness of counterparties to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

Certain of our customers may be temporarily unable to meet their current obligations. While this may cause disruption to cash flows, we believe that we are properly positioned to deal with the potential disruption because the vast majority of our gathering assets are strategically positioned at the beginning of the midstream value chain. The majority of our infrastructure is connected directly to our customers' wellheads and pad sites, which means our gathering systems are typically the first third-party infrastructure through which our customers' commodities flow and, in many cases, the only way for our customers to get their production to market.

We have exposure due to nonperformance under our MVC contracts whereby a customer, who was not meeting its MVCs, does not have the wherewithal to make its MVC shortfall payments when they become due. We typically receive payment for all prior-year MVC shortfall billings in the quarter immediately following billing. Therefore, our exposure to risk of nonperformance is limited to and accumulates during the current year-to-date contracted measurement period.

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For additional information, see Notes 4, 9 and 11 to the consolidated financial statements.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of or during the year ended December 31, 2018.

Critical Accounting Estimates

We prepare our financial statements in accordance with GAAP. These principles are established by the FASB. We employ methods, estimates and assumptions based on currently available information when recording transactions resulting from business operations. Our significant accounting policies are described in Note 2 to the consolidated financial statements.

The estimates that we deem to be most critical to an understanding of our financial position and results of operations are those related to determination of fair value and recognition of deferred revenue. The preparation and evaluation of these critical accounting estimates involve the use of various assumptions developed from management's analyses and judgments. Subsequent experience or use of other methods, estimates or assumptions could produce significantly different results. Our critical accounting estimates are as follows:

Recognition and Impairment of Long-Lived Assets

Our long-lived assets include property, plant and equipment, amortizing intangible assets and goodwill.

Property, Plant and Equipment and Amortizing Intangible Assets. As of December 31, 2018, we had net property, plant and equipment with a carrying value of approximately $2.0 billion and net amortizing intangible assets with a carrying value of approximately $273.4 million.

When evidence exists that we will not be able to recover a long-lived asset's carrying value through future cash flows, we write down the carrying value of the asset to its estimated fair value. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable as well as in connection with any goodwill impairment evaluations.

With respect to property, plant and equipment and our amortizing intangible assets, the carrying value of a long-lived asset is not recoverable if the carrying value exceeds the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposal. In this situation, we recognize an impairment loss equal to the amount by which the carrying value exceeds the asset's fair value. We determine fair value using an income-based approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash flows. Any impairment determinations involve significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these estimates are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

2018 Impairments. In December 2018, in connection with certain strategic initiatives, we performed a recoverability assessment of certain assets within the Williston Basin reporting segment. Based on the results, we concluded that the carrying value of certain long-lived assets related to the Tioga Midstream system within the Williston Basin were not fully recoverable. We recorded an impairment charge of $3.9 million related to these assets after comparing the fair value of the long-lived assets to their carrying values. In addition, we reviewed other assets that had been identified as potentially impaired and recognized long-lived asset impairments as detailed in Note 5 to the consolidated financial statements.

2017 Impairments. In December 2017, in connection with certain strategic initiatives, we performed a financial review of certain assets within the Williston Basin reporting segment. This resulted in a triggering event that required us to perform a recoverability test. Based on the results of the test, we concluded that the carrying value of certain long-lived assets and the related intangible assets related to the Bison Midstream system in the Williston Basin were not fully recoverable. As a result, we recorded an impairment charge of $101.9 million related to the long-lived assets and $85.2 million related to contract intangibles assets.

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For additional information, see Notes 2, 5 and 6 to the consolidated financial statements.

Goodwill. We evaluate goodwill for impairment annually on September 30 and whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value, including goodwill.

2018, 2017 and 2016 Impairment Evaluations. We performed our 2018, 2017 and 2016 annual goodwill impairment analysis as of September 30 and concluded that none of our goodwill had been impaired.

See Notes 2 and 7 for additional information.

Deferred Purchase Price Obligation

We recognized the Deferred Purchase Price Obligation to reflect the present value of the Remaining Consideration. Our calculation of the Remaining Consideration incorporates:

- actual capital expenditures and Business Adjusted EBITDA related to the 2016 Drop Down Assets for the period from March 3, 2016 through the respective balance sheet date; and
- estimates of (i) capital expenditures made between the respective balance sheet date and December 31, 2019 and (ii) Business Adjusted EBITDA, an income-based measure, during the period from the respective balance sheet date to December 31, 2019. The calculation of the prospective component of Remaining Consideration represents management's best estimate of these two financial measures.

We then discount the Remaining Consideration using a commensurate risk-adjusted discount rate and recognize the present value on our consolidated balance sheets with the change in present value recognized in earnings in the period of change.

The estimates and expectations used in calculating the prospective component of Remaining Consideration and the present value calculation of the Remaining Consideration involve a significant amount of judgment as the calculations are, in part, based on future events and/or conditions, including (i) revenues, (ii) estimates of future volume throughput, capital expenditures, operating costs and their timing and (iii) economic and regulatory climates, among other factors. Our estimates of these inputs are inherently imprecise because they reflect our expectation of future conditions that are largely outside of our control. While the assumptions used are consistent with our current business plans and investment decisions, these assumptions could change significantly during the period leading up to settlement of the Deferred Purchase Price Obligation. See Notes 17 and 19 to the consolidated financial statements and “Business – Recent Developments” for additional information.

Minimum Volume Commitments

Deferred Revenue. We record customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering or processing fees in subsequent periods. We recognize deferred revenue under these arrangements in revenue when (i) we consider it remote that the customer will utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods; (ii) the customer incurs a shortfall in a contract with no banking mechanism or claw back provision; (iii) the customer’s banking mechanism has expired; or (iv) it is remote that the customer will use its unexercised right. We also recognize deferred revenue when it is determined that a given amount of MVC shortfall payments cannot be recovered by offsetting gathering or processing fees in subsequent contracted measurement periods. In making this determination, we consider both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is twelve months or less. We classify deferred revenue as noncurrent for arrangements where the expiration of the right to utilize shortfall payments and our estimate of its potential utilization is more than 12 months. As of December 31, 2018, current deferred revenue totaled $11.5 million. Noncurrent deferred revenue totaled $39.5

million at December 31, 2018 and represents amounts that provide these customers the ability to offset their gathering fees, as determined by the MVC contract, to the extent that their throughput volumes exceed their MVC.

Adjustments for MVC Shortfall Payments. We estimate the impact of expected MVC shortfall payments for inclusion in our calculation of segment adjusted EBITDA. Adjustments related to MVC shortfall payments account for:

- the net increases or decreases in deferred revenue for MVC shortfall payments and
- our inclusion of expected annual or multi-year MVC shortfall payments. With respect to the impact of a net change in deferred revenue for MVC shortfall payments, we treated increases in deferred revenue balances as a favorable adjustment to segment adjusted EBITDA, while decreases in deferred revenue balances were treated as an unfavorable adjustment to segment adjusted EBITDA. We also included a proportional amount of any historical and expected MVC shortfall payments in each quarter prior to the quarter in which we actually recognized the shortfall payment.

We estimate expected MVC shortfall payments based on assumptions including, but not limited to, contract terms, historical volume throughput data and expectations regarding future investment, drilling and production.

For additional information, see Notes 2, 4 and 9 to the consolidated financial statements and the "Results of Operations" and "Liquidity and Capital Resources—Credit and Counterparty Concentration Risks" sections herein.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this report as well as in periodic press releases and certain oral statements made by our officers and employees during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “v “should,” “would,” and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us, our subsidiaries, Summit Investments or our Sponsor, are also forward-looking statements. These forward-looking statements involve various risks and uncertainties, including, but not limited to, those described in Item 1A. Risk Factors included in this report.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this report and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements in this paragraph. These risks and uncertainties include, among others:

- our ability to grow, or maintain, our current rate of cash distributions;
- fluctuations in natural gas, NGLs and crude oil prices;
- the extent and success of our customers' drilling efforts, as well as the quantity of natural gas, crude oil and produced water volumes produced within proximity of our assets;
- failure or delays by our customers in achieving expected production in their natural gas, crude oil and produced water projects;
- competitive conditions in our industry and their impact on our ability to connect hydrocarbon supplies to our gathering and processing assets or systems;

- actions or inactions taken or nonperformance by third parties, including suppliers, contractors, operators, processors, transporters and customers, including the inability or failure of our shipper customers to meet their financial obligations under our gathering agreements and our ability to enforce the terms and conditions of certain of our gathering agreements in the event of a bankruptcy of one or more of our customers;
- the ability to attract and retain key management personnel;

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- commercial bank and capital market conditions and the potential impact of changes or disruptions in the credit and/or equity capital markets;
- changes in the availability and cost of capital and the results of our financing efforts, including availability of funds in the credit and/or equity capital markets;
- restrictions placed on us by the agreements governing our debt and preferred equity instruments;
- the availability, terms and cost of downstream transportation and processing services;
- natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- operational risks and hazards inherent in the gathering, treating and/or processing of natural gas, crude oil and produced water;
- weather conditions and terrain in certain areas in which we operate;
- any other issues that can result in deficiencies in the design, installation or operation of our gathering, treating and processing facilities;
- timely receipt of necessary government approvals and permits, our ability to control the costs of construction, including costs of materials, labor and rights-of-way and other factors that may impact our ability to complete projects within budget and on schedule;
- the effects of existing and future laws and governmental regulations, including environmental, safety and climate change requirements;
- changes in tax status;
- the effects of litigation;
- changes in general economic conditions; and
- certain factors discussed elsewhere in this report.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected or cause a significant reduction in the market price of our common units, preferred units and senior notes.

The foregoing list of risks and uncertainties may not contain all of the risks and uncertainties that could affect us. In addition, in light of these risks and uncertainties, the matters referred to in the forward-looking statements contained in this document may not in fact occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

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## Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

### Interest Rate Risk

Our current interest rate risk exposure is largely related to our debt portfolio. As of December 31, 2018, we had $800.0 million principal of fixed-rate Senior Notes and $466.0 million outstanding under our variable rate Revolving Credit Facility (see Note 10 to the consolidated financial statements). While existing fixed-rate debt mitigates the downside impact of fluctuations in interest rates, future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher overall interest costs. In addition, the borrowings under our Revolving Credit Facility, which have a variable interest rate, also expose us to the risk of increasing interest rates. For the year ended December 31, 2018, a hypothetical 1% increase (decrease) in interest rates would have increased (decreased) our interest expense by approximately $3.6 million assuming no changes in amounts drawn or other variables under our Revolving Credit Facility or Senior Notes.

### Commodity Price Risk

We currently generate a majority of our revenues pursuant to primarily long-term and fee-based gathering agreements, many of which include MVCs and areas of mutual interest. Our direct commodity price exposure relates to (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River systems, (ii) natural gas and crude oil marketing services in and around our gathering systems, (iii) the sale of natural gas we retain from certain DFW Midstream customers and (iv) the sale of condensate we retain from our gathering services at Grand River. Our gathering agreements with certain DFW Midstream customers permit us to retain a certain quantity of natural gas that we sell to offset the power costs we incur to operate our electric-drive compression assets. Our gathering agreements with our Grand River customers permit us to retain condensate volumes from the Grand River system gathering lines. We manage our direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices on the Waha Hub Index. We sell retainage natural gas at prices that are based on the Waha Hub Index and/or the Atmos Zone 3 Index. By basing the power prices on an index and basin-relevant market, we are able to closely associate the relationship between the compression electricity expense and natural gas retainage sales. We do not enter into risk management contracts for speculative purposes.

Item 8. Financial Statements and Supplementary Data.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Summit Midstream GP, LLC and the unitholders of Summit Midstream Partners, LP
The Woodlands, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2018 and 2017, 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 (collectively referred to as the "financial statements"). In our opinion, based on our audits and the reports of the other auditors, the financial statements present fairly, in all material respects, the financial position of the Partnership as of 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 accounting principles generally accepted in the United States of America.

We did not audit the financial statements of Ohio Gathering Company, L.L.C. ("Ohio Gathering") as of and for the years ended December 31, 2018, 2017, and 2016 or Ohio Condensate Company, L.L.C. ("Ohio Condensate") for the year ended December 31, 2016, the Partnership's investments in which are accounted for by use of the equity method. The accompanying financial statements of the Partnership include its equity investment in Ohio Gathering of \$642,036,000 and \$683,468,000 as of December 31, 2018 and 2017, respectively, and its income (loss) from equity method investees in Ohio Gathering of \$(11,085,000), \$(1,823,000), and \$7,451,000 for the years ended December 31, 2018, 2017 and 2016, respectively, and Ohio Condensate of \$(37,795,000) for the year ended December 31, 2016. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Ohio Gathering and Ohio Condensate, is based solely on the reports of the other auditors.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2019 expressed an unqualified opinion on the Partnership's internal control over financial reporting based on our audit.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership'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 Partnership 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 and the reports of the other auditors provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 26, 2019

We have served as the Partnership's auditor since 2009.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| | (In thousands, except unit amounts) | |
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $4,345 | $ 1,430 |
| Accounts receivable | 97,936 | 72,301 |
| Other current assets | 3,971 | 4,327 |
| Total current assets | 106,252 | 78,058 |
| Property, plant and equipment, net | 1,963,713 | 1,795,129 |
| Intangible assets, net | 273,416 | 301,345 |
| Goodwill | 16,211 | 16,211 |
| Investment in equity method investees | 649,250 | 690,485 |
| Other noncurrent assets | 11,720 | 13,565 |
| Total assets | $3,020,562 | $ 2,894,793 |
| Liabilities and Partners' Capital | | |
| Current liabilities: | | |
| Trade accounts payable | $38,414 | $ 16,375 |
| Accrued expenses | 21,963 | 12,499 |
| Due to affiliate | 240 | 1,088 |
| Deferred revenue | 11,467 | 4,000 |
| Ad valorem taxes payable | 10,550 | 8,329 |
| Accrued interest | 12,286 | 12,310 |
| Accrued environmental remediation | 2,487 | 3,130 |
| Other current liabilities | 12,645 | 11,258 |
| Total current liabilities | 110,052 | 68,989 |
| Long-term debt | 1,257,731 | 1,051,192 |
| Deferred Purchase Price Obligation | 383,934 | 362,959 |
| Noncurrent deferred revenue | 39,504 | 12,707 |
| Noncurrent accrued environmental remediation | 3,149 | 2,214 |
| Other noncurrent liabilities | 4,968 | 7,063 |
| Total liabilities | 1,799,338 | 1,505,124 |
| Commitments and contingencies (Note 16) | | |
| Series A Preferred Units (300,000 units issued and outstanding at December 31, 2018 and December 31, 2017) | 293,616 | 294,426 |
| Common limited partner capital (73,390,853 units issued and outstanding | 902,358 | 1,056,510 |

| | | |
|---|---|---|
| at December 31, 2018 and 73,085,996 units issued and outstanding | | |
| at December 31, 2017) | | |
| General Partner interests (1,490,999 units issued and outstanding at | | |
| December 31, 2018 and December 31, 2017) | 25,250 | 27,920 |
| Noncontrolling interest | - | 10,813 |
| Total partners' capital | 1,221,224 | 1,389,669 |
| Total liabilities and partners' capital | $3,020,562 | $ 2,894,793 |

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands, except per-unit amounts) | | |
| Revenues: | | | |
| Gathering services and related fees | $344,616 | $394,427 | $345,961 |
| Natural gas, NGLs and condensate sales | 134,834 | 68,459 | 35,833 |
| Other revenues | 27,203 | 25,855 | 20,568 |
| Total revenues | 506,653 | 488,741 | 402,362 |
| Costs and expenses: | | | |
| Cost of natural gas and NGLs | 107,661 | 57,237 | 27,421 |
| Operation and maintenance | 96,878 | 93,882 | 95,334 |
| General and administrative | 52,877 | 54,681 | 52,410 |
| Depreciation and amortization | 107,100 | 115,475 | 112,239 |
| Transaction costs | — | 73 | 1,321 |
| Loss on asset sales, net | — | 527 | 93 |
| Long-lived asset impairment | 7,186 | 188,702 | 1,764 |
| Total costs and expenses | 371,702 | 510,577 | 290,582 |
| Other (expense) income | (169) | 298 | 116 |
| Interest expense | (60,535) | (68,131) | (63,810) |
| Early extinguishment of debt | — | (22,039) | — |
| Deferred Purchase Price Obligation | (20,975) | 200,322 | (55,854) |
| Income (loss) before income taxes and loss from equity method investees | 53,272 | 88,614 | (7,768) |
| Income tax expense | (33) | (341) | (75) |
| Loss from equity method investees | (10,888) | (2,223) | (30,344) |
| Net income (loss) | $42,351 | $86,050 | $(38,187) |
| Less: | | | |
| Net income attributable to Summit Investments | — | — | 2,745 |
| Net income (loss) attributable to noncontrolling interest | 168 | 363 | (14) |
| Net income (loss) attributable to SMLP | 42,183 | 85,687 | (40,918) |
| Net income attributable to General Partner, including IDRs | 9,384 | 10,202 | 7,261 |
| Net income (loss) attributable to limited partners | 32,799 | 75,485 | (48,179) |
| Net income attributable to Series A Preferred Units | 28,500 | 3,563 | — |
| Net income (loss) attributable to common limited partners | $4,299 | $71,922 | $(48,179) |
| | | | |
| Earnings (loss) per limited partner unit: | | | |
| Common unit – basic | $0.06 | $0.99 | $(0.71) |

| | | | |
|---|---|---|---|
| Common unit – diluted | $0.06 | $0.98 | $(0.71 ) |
| | | | |
| Weighted-average limited partner units outstanding: | | | |
| Common units – basic | 73,304 | 72,705 | 68,264 |
| Common units – diluted | 73,615 | 73,047 | 68,264 |

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

| | Partners' capital | | | | Summit Investments' equity in contributed subsidiaries | Total |
|---|---|---|---|---|---|---|
| | Limited partners | | | | | |
| | Common | Subordinated | General Partner | Noncontrolling interest | | |
| | (In thousands) | | | | | |
| Partners' capital, January 1, 2016 | $744,977 | $213,631 | $25,634 | $— | $763,057 | $1,747,299 |
| Net (loss) income | (49,219) | 1,040 | 7,261 | (14) | 2,745 | (38,187) |
| Distributions to unitholders | (142,214) | (14,034) | (11,256) | — | — | (167,504) |
| Unit-based compensation | 7,550 | — | — | — | — | 7,550 |
| Tax withholdings on vested SMLP LTIP awards | (1,181) | — | — | — | — | (1,181) |
| Issuance of common units, net of offering costs | 125,233 | — | — | — | — | 125,233 |
| Contribution from General Partner | — | — | 2,702 | — | — | 2,702 |
| Subordinated units conversion | 200,637 | (200,637) | — | — | — | — |
| Purchase of 2016 Drop Down Assets | — | — | — | — | (866,858) | (866,858) |
| Establishment of noncontrolling interest | — | — | — | 11,261 | (11,261) | — |
| Distribution of debt related to Carve-Out Financial Statements of Summit Investments | — | — | — | — | 342,926 | 342,926 |
| Excess of acquired carrying value over consideration paid for 2016 Drop Down Assets | 243,044 | — | 4,953 | — | (247,997) | — |
| Cash advance from Summit Investments to contributed subsidiaries, net | — | — | — | — | 12,214 | 12,214 |
| | — | — | — | — | 4,821 | 4,821 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | | | | | | |
| Capitalized interest allocated from Summit Investments to contributed subsidiaries | — | — | — | — | 223 | 223 |
| Class B membership interest noncash compensation | 305 | — | — | — | 130 | 435 |
| Partners' capital, December 31, 2016 | $1,129,132 | $— | $29,294 | $ 11,247 | $— | $1,169,673 |

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**SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES**

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

(continued)

| | Partners' capital Limited partners Series A Preferred Units | Common | General Partner | Noncontrolling interest | Total |
|---|---|---|---|---|---|
| | (In thousands) | | | | |
| Partners' capital, December 31, 2016 | $— | $1,129,132 | $29,294 | $ 11,247 | $1,169,673 |
| Net income | 3,563 | 71,922 | 10,202 | 363 | 86,050 |
| Distributions to unitholders | (2,375) | (167,062) | (12,041) | — | (181,478) |
| Unit-based compensation | — | 7,878 | — | — | 7,878 |
| Tax withholdings on vested SMLP LTIP awards | — | (2,236) | — | — | (2,236) |
| Issuance of Series A Preferred Units, net of offering costs | 293,238 | — | — | — | 293,238 |
| ATM Program issuances, net of costs | — | 17,078 | — | — | 17,078 |
| Contribution from General Partner | — | — | 465 | — | 465 |
| Purchase of noncontrolling interest | — | — | — | (797) | (797) |
| Other | — | (202) | — | — | (202) |
| Partners' capital, December 31, 2017, as reported | $294,426 | $1,056,510 | $27,920 | $ 10,813 | $1,389,669 |
| January 1, 2018 impact of Topic 606 day 1 adoption | — | 4,130 | 84 | — | 4,214 |
| Partners' capital, January 1, 2018 | 294,426 | 1,060,640 | 28,004 | 10,813 | 1,393,883 |
| Net income | 28,500 | 4,299 | 9,384 | 168 | 42,351 |
| Distributions to unitholders | (28,500) | (168,567) | (12,138) | — | (209,205) |
| Unit-based compensation | — | 8,088 | — | — | 8,088 |
| Tax withholdings on vested SMLP LTIP awards | — | (1,974) | — | — | (1,974) |
| Purchase of noncontrolling interest | — | — | — | (10,981) | (10,981) |
| Other | (810) | (128) | — | — | (938) |
| Partners' capital, December 31, 2018 | $293,616 | $902,358 | $25,250 | $ — | $1,221,224 |

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Cash flows from operating activities: | | | |
| Net income (loss) | $42,351 | $86,050 | $(38,187) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation and amortization | 106,767 | 114,872 | 112,661 |
| Amortization of debt issuance costs | 4,285 | 4,158 | 3,976 |
| Deferred Purchase Price Obligation | 20,975 | (200,322) | 55,854 |
| Unit-based and noncash compensation | 8,328 | 7,951 | 7,985 |
| Loss from equity method investees | 10,888 | 2,223 | 30,344 |
| Distributions from equity method investees | 35,271 | 40,220 | 44,991 |
| Loss on asset sales, net | — | 527 | 93 |
| Long-lived asset impairment | 7,186 | 188,702 | 1,764 |
| Early extinguishment of debt | — | 22,039 | — |
| Write-off of debt issuance costs | — | 302 | — |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | (21,535) | 25,063 | (7,783) |
| Trade accounts payable | 81 | (3,246) | 2,001 |
| Accrued expenses | 9,464 | 1,110 | 4,613 |
| Due (to) from affiliate | (848) | 830 | (891) |
| Deferred revenue, net | 5,355 | (40,758) | 11,302 |
| Ad valorem taxes payable | 2,221 | (2,259) | 317 |
| Accrued interest | (24) | (5,173) | — |
| Accrued environmental remediation, net | (3,808) | (4,109) | (4,211) |
| Other, net | 972 | (348) | 5,666 |
| Net cash provided by operating activities | 227,929 | 237,832 | 230,495 |
| Cash flows from investing activities: | | | |
| Capital expenditures | (200,586) | (124,215) | (142,719) |
| Proceeds from asset sale | 496 | 2,300 | — |
| Contributions to equity method investees | (4,924) | (25,513) | (31,582) |
| Acquisitions of gathering systems from affiliate, net of acquired cash | — | — | (359,431) |
| Purchase of noncontrolling interest | (10,981) | (797) | — |
| Other, net | (284) | (458) | (394) |
| Net cash used in investing activities | (216,279) | (148,683) | (534,126) |

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**SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES**

CONSOLIDATED STATEMENTS OF CASH FLOWS

(continued)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Cash flows from financing activities: | | | |
| Distributions to common unitholders | (180,705) | (179,103) | (167,504) |
| Distributions to Series A Preferred unitholders | (28,500) | (2,375) | — |
| Borrowings under Revolving Credit Facility | 289,000 | 247,500 | 520,300 |
| Repayments under Revolving Credit Facility | (84,000) | (634,500) | (204,300) |
| Debt issuance costs | (344) | (16,390) | (3,032) |
| Payment of redemption and call premiums on senior notes | — | (17,932) | — |
| Proceeds from ATM Program common unit issuances, net of costs | — | 17,078 | — |
| Proceeds from underwritten issuance of common units, net of costs | — | — | 125,233 |
| Proceeds from issuance of Series A Preferred Units, net of costs | — | 293,238 | — |
| Contribution from General Partner | — | 465 | 2,702 |
| Cash advance from Summit Investments to contributed subsidiaries, net | — | — | 12,214 |
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | — | — | 4,821 |
| Issuance of senior notes | — | 500,000 | — |
| Tender and redemption of senior notes | — | (300,000) | — |
| Other, net | (4,186) | (3,128) | (1,168) |
| Net cash (used in) provided by financing activities | (8,735) | (95,147) | 289,266 |
| Net change in cash and cash equivalents | 2,915 | (5,998) | (14,365) |
| Cash and cash equivalents, beginning of period | 1,430 | 7,428 | 21,793 |
| Cash and cash equivalents, end of period | $4,345 | $1,430 | $7,428 |
| | | | |
| Supplemental cash flow disclosures: | | | |
| Cash interest paid | $64,678 | $71,488 | $63,000 |
| Less capitalized interest | 8,497 | 2,579 | 3,709 |
| Interest paid (net of capitalized interest) | $56,181 | $68,909 | $59,291 |
| | | | |
| Cash paid for taxes | $175 | $— | $— |

| | | | |
|---|---|---|---|
| Noncash investing and financing activities | | | |
| Capital expenditures in trade accounts payable (period-end accruals) | $33,750 | $11,792 | $8,422 |
| Capital expenditures relating to contributions in aid of construction for Topic 606 day 1 adoption | 33,123 | — | — |
| Issuance of Deferred Purchase Price Obligation to affiliate to partially fund the 2016 Drop Down | — | — | 507,427 |
| Excess of acquired carrying value over consideration paid and recognized for 2016 Drop Down Assets | — | — | 247,997 |
| Distribution of debt related to Carve-Out Financial Statements of Summit Investments | — | — | 342,926 |
| Capitalized interest allocated to contributed subsidiaries from Summit Investments | — | — | 223 |

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

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**SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

Organization. SMLP, a Delaware limited partnership, was formed in May 2012 and began operations in October 2012 in connection with its IPO of common limited partner units. SMLP is a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in the continental United States. Our business activities are conducted through various operating subsidiaries, each of which is owned or controlled by our wholly owned subsidiary holding company, Summit Holdings, a Delaware limited liability company. References to the "Partnership," "we," or "our" refer collectively to SMLP and its subsidiaries.

The General Partner, a Delaware limited liability company, manages our operations and activities. Summit Investments, a Delaware limited liability company, is the ultimate owner of our General Partner and has the right to appoint the entire Board of Directors. Summit Investments is controlled by Energy Capital Partners.

In addition to its approximate 2% general partner interest in SMLP (including the IDRs), Summit Investments has indirect ownership interests in our common units. As of December 31, 2018, Summit Investments beneficially owned 25,854,581 SMLP common units and a subsidiary of Energy Capital Partners directly owned 5,915,827 SMLP common units. On February 26, 2019, we announced an equity restructuring agreement with the General Partner and SMP Holdings pursuant to which, upon closing, the IDRs and the 2% general partner interest will be converted into 8,750,000 common units and a non-economic general partner interest. The closing of the equity restructuring agreement is subject to certain conditions.

Neither SMLP nor its subsidiaries have any employees. All of the personnel that conduct our business are employed by Summit Investments, but these individuals are sometimes referred to as our employees.

Business Operations. We provide natural gas gathering, treating and processing services as well as crude oil and produced water gathering services pursuant to primarily long-term, fee-based agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather, compress, treat and/or process as well as by the volumes of crude oil and produced water that we gather. We are the owner-operator of or have significant ownership interests in the following gathering systems:

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;
- Ohio Gathering, a natural gas gathering system and a condensate stabilization facility operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;
- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Tioga Midstream, a crude oil, produced water and associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;

- Bison Midstream, an associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Niobrara G&P, an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara and Codell shale formations in northeastern Colorado;
- Summit Permian, an associated natural gas gathering and processing system in the northern Delaware Basin, which includes the Wolfcamp and Bone Spring formations, in southeastern New Mexico;
- Grand River, a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah;

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- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia.

Summit Marketing provides natural gas and crude oil marketing services in and around our gathering systems.

In February 2016, the Partnership and SMP Holdings, a wholly owned subsidiary of Summit Investments, entered into a contribution agreement (the "Contribution Agreement") pursuant to which SMP Holdings agreed to contribute to the Partnership substantially all of its limited partner interest in OpCo, a Delaware limited partnership that owns (i) 100% of the issued and outstanding membership interests of Summit Utica, Meadowlark Midstream and Tioga Midstream (collectively, the “Contributed Entities”), each a limited liability company and (ii) a 40% ownership interest in each of OGC and OCC (collectively with OpCo and the Contributed Entities, the “2016 Drop Down Assets”)(the “2016 Drop Down”). The 2016 Drop Down closed in March 2016; concurrent therewith, a subsidiary of Summit Investments retained a 1% noncontrolling interest in OpCo. In a series of transactions in December 2017 and November 2018, we purchased the 1% noncontrolling interest in OpCo. As a result of these transactions, other than our investment in Ohio Gathering, all of our business activities are now conducted through wholly owned operating subsidiaries.

Presentation and Consolidation. We prepare our consolidated financial statements in accordance with GAAP as established by the FASB. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the balance sheet dates, including fair value measurements, the reported amounts of revenue and expense and the disclosure of contingencies. Although management believes these estimates are reasonable, actual results could differ from its estimates.

The consolidated financial statements include the assets, liabilities and results of operations of SMLP and its subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation. Comprehensive income or loss is the same as net income or loss for all periods presented.

SMLP recognized its drop down acquisitions at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment over the consideration paid and recognized for a contributed subsidiary is recognized as an addition to partners' capital, while the excess of purchase price paid and recognized over net investment is recognized as a reduction to partners' capital. Due to the common control aspect, we account for drop down transactions on an “as-if pooled” basis for the periods during which common control existed.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents. We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable. Accounts receivable relate to gathering and other services provided to our customers and other counterparties. We evaluate the collectability of accounts receivable and the need for an allowance for doubtful accounts based on customer-specific facts and circumstances. To the extent we doubt the collectability of a specific customer or counterparty receivable, we recognize an allowance for doubtful accounts. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Property, Plant and Equipment.  We record property, plant and equipment at historical cost of construction or fair value of the assets at acquisition. We capitalize expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, we recognize expenditures as an expense as incurred. We capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress.

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We record depreciation on a straight-line basis over an asset's estimated useful life. We base our estimates for useful life on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Estimates of useful lives follow.

| | Useful lives (In years) |
|---|---|
| | (In years) |
| Gathering and processing systems and related equipment | 12-30 |
| Other | 4-15 |

Construction in progress is depreciated consistent with its applicable asset class once it is placed in service. Land and line fill are not depreciated.

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. Upon sale, retirement or other disposal, we remove the carrying value of an asset and its accumulated depreciation from our balance sheet and recognize the related gain or loss, if any.

Accrued capital expenditures are reflected in trade accounts payable.

Asset Retirement Obligations. We record a liability for asset retirement obligations only if and when a future asset retirement obligation with a determinable life is identified. For identified asset retirement obligations, we then evaluate whether the expected date and related costs of retirement can be estimated. We have concluded that our gathering and processing assets have an indeterminate life because they are owned and will operate for an indeterminate period when properly maintained. Because we did not have sufficient information to reasonably estimate the amount or timing of such obligations and we have no current plan to discontinue use of any significant assets, we did not provide for any asset retirement obligations as of December 31, 2018 or 2017.

Amortizing Intangibles. Upon the acquisition of DFW Midstream, certain of its gas gathering contracts were deemed to have above-market pricing structures. We have recognized the above-market contracts as favorable gas gathering contracts. We amortize the favorable contracts using a straight-line method over the contract's estimated useful life. We define useful life as the period over which the contract is expected to contribute to our future cash flows. These contracts have original terms ranging from 10 years to 20 years. We recognize the amortization expense associated with these contracts in other revenues.

We amortize all other gas gathering contracts, or contract intangibles, over the period of economic benefit based upon expected revenues over the life of the contract. The useful life of these contracts ranges from 3 years to 25 years. We recognize the amortization expense associated with these contracts in depreciation and amortization expense.

We have rights-of-way associated with city easements and easements granted within existing rights-of-way. We amortize these intangible assets over the shorter of the contractual term of the rights-of-way or the estimated useful life of the gathering system. The contractual terms of the rights-of-way range from 20 years to 30 years. We recognize the amortization expense associated with rights-of-way assets in depreciation and amortization expense.

Goodwill.  Goodwill represents consideration paid in excess of the fair value of the net identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on September 30. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We test goodwill for impairment using a quantitative test. We compare the fair value of the reporting unit to its carrying value, including goodwill. To estimate the fair value of the reporting units, we utilize two valuation methodologies: the market approach and the income approach. Both of these approaches incorporate significant estimates and assumptions to calculate enterprise fair value for a reporting unit. The most significant estimates and assumptions inherent within these two valuation methodologies are: (i) determination of the weighted-average cost of capital; (ii) the selection of guideline public companies; (iii) market multiples; (iv) weighting of the income and market approaches (v) growth rates; (vi) commodity prices; and (vii) the expected levels of throughput volume gathered. Changes in these and other assumptions could materially affect the estimated amount of fair value for any of our reporting units.

If the reporting unit's fair value exceeds its carrying amount, we conclude that the goodwill of the reporting unit has not been impaired and no further work is performed.

If we determine that the reporting unit's carrying value exceeds its fair value, we recognize the excess of the carrying value over the fair value as an impairment loss.

Equity Method Investments. We account for investments in which we exercise significant influence using the equity method so long as we (i) do not control the investee and (ii) are not the primary beneficiary. We recognize these investments in investment in equity method investees in the accompanying consolidated balance sheets. We recognize our proportionate share of earnings or loss in net income on a one-month lag based on the financial information available to us during the reporting period.

We recognize an other-than-temporary impairment for losses in the value of equity method investees when evidence indicates that the carrying amount is no longer supportable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. A current fair value of an investment that is less than its carrying amount may indicate a loss in value of the investment. We evaluate our equity method investments whenever evidence exists that would indicate a need to assess the investment for potential impairment.

Other Noncurrent Assets. Other noncurrent assets primarily consist of external costs incurred in connection with the closing of our Revolving Credit Facility and related amendments. We capitalize and then amortize these debt issuance costs on a straight-line basis, which approximates the effect of the effective interest rate method, over the life of the respective debt instrument. We recognize the amortization of the Revolving Credit Facility debt issuance costs in interest expense.

Debt Issuance Costs. Debt issuance costs, other than those associated with our Revolving Credit Facility, are reflected in the carrying value of the Senior Notes as an adjustment to the principal amount and amortized on a straight-line basis, which approximates the effect of the effective interest rate method, over the life of the respective debt instrument. We recognize the amortization of the Senior Notes debt issuance costs in interest expense.

Deferred Purchase Price Obligation. We recognize a liability for the Deferred Purchase Price Obligation to reflect the present value of the estimated Remaining Consideration to be paid in 2020 for the acquisition of the 2016 Drop Down Assets. We estimate Remaining Consideration by summing the calculations of (i) actual capital expenditures incurred and Business Adjusted EBITDA (as defined later) recognized from the 2016 Drop Down Assets during the period since closing the 2016 Drop Down to the current balance sheet date and (ii) estimates of projected capital expenditures and Business Adjusted EBITDA related to the 2016 Drop Down Assets for periods subsequent to the respective balance sheet date until December 31, 2019. We discount the Remaining Consideration using a commensurate risk-adjusted discount rate and recognize the change in present value of the Remaining Consideration in earnings in the period of change. Our recognition of the change in present value of the Remaining Consideration in the consolidated statements of operations represents the change in present value, which comprises a time value of money concept, as well as (i) actual results from the 2016 Drop Down Assets and (ii) adjustments to projections and the expected value of the Remaining Consideration (see Notes 17 and 19 for additional information).

Impairment of Long-Lived Assets. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset (except goodwill) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If we conclude that an asset's carrying value will not be recovered through future cash flows, we recognize an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. We determine fair value using either a market-based approach, an income-based approach or a combination of the two approaches.

Derivative Contracts. We have commodity price exposure related to our sale of the physical natural gas we retain from certain DFW Midstream customers and our procurement of electricity to operate the DFW Midstream system's electric-drive compression assets. Our gas gathering agreements with certain DFW Midstream customers permit us

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to retain a certain quantity of natural gas that we gather to offset the power costs we incur to operate these electric-drive compression assets. We manage this direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices based on the Waha Hub Index. We sell retainage natural gas at prices that are based on the Waha Hub Index and/or the Atmos Zone 3 Index. By basing the power prices on an index and basin-relevant market, we are able to closely associate the relationship between the compression electricity expense and natural gas retainage sales.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections and hedge accounting designations, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. We have designated these contracts as normal under the normal purchase and sale exception under the accounting standards for derivatives. We do not enter into risk management contracts for speculative purposes.

Fair Value of Financial Instruments. The fair-value-measurement standard under GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which the inputs are observable. The three levels of the fair value hierarchy are as follows:

- Level 1. Inputs represent quoted prices in active markets for identical assets or liabilities;
- Level 2. Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs); and
- Level 3. Inputs that are not observable from objective sources, such as management’s internally developed assumptions used in pricing an asset or liability (for example, an internally developed present value of future cash flows model that underlies management's fair value measurement).

Commitments and Contingencies. We record accruals for loss contingencies when we determine that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. We recognize gain contingencies when their realization is assured beyond a reasonable doubt.

Noncontrolling Interest. Noncontrolling interest represents the ownership interests of third-party entities in the net assets of our consolidated subsidiaries. For financial reporting purposes, we consolidate OpCo and its wholly owned subsidiaries with our wholly owned subsidiaries and through October 2018, the 1% ownership interest in OpCo was reflected as noncontrolling interest in partners' capital. We reflected changes in our ownership of OpCo as adjustments to noncontrolling interest. See Note 12 for additional information.

Revenue Recognition. The majority of our revenue is derived from long-term, fee-based contracts with original terms of up to 25 years. We account for revenue in accordance with Topic 606, which we adopted on January 1, 2018, using the modified retrospective method. See below for further discussion of the adoption.

We recognize revenue earned from fee-based gathering, treating and processing services in gathering services and related fees. We also earn revenue in the Williston Basin reporting segment from the sale of physical natural gas purchased from our customers under certain percent-of-proceeds arrangements; under Topic 606, fees from these arrangements are presented net within cost of natural gas and NGLs. We sell natural gas that we retain from certain

DFW Midstream customers to offset the power expenses of the electric-driven compression on the DFW Midstream system. We also sell condensate retained from our gathering services at Grand River. Revenues from the sale of natural gas and condensate are recognized in natural gas, NGLs and condensate sales; the associated expense is included in operation and maintenance expense. Certain customers reimburse us for costs we incur on their behalf.

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We record costs incurred and reimbursed by our customers on a gross basis, with the revenue component recognized in other revenues.

We provide gathering and/or processing services principally under contracts that contain one or more of the following arrangements:

- ***Fee-based arrangements.*** Under fee-based arrangements, we receive a fee or fees for one or more of the following services (i) natural gas gathering, treating and/or processing and (ii) crude oil and/or produced water gathering.
- ***Percent-of-proceeds arrangements.*** Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat the natural gas, process the natural gas and/or sell the natural gas to a third party for processing. We then remit to our producers an agreed-upon percentage of the actual proceeds received from sales of the residue natural gas and NGLs. Certain of these arrangements may also result in returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. The margins earned are directly related to the volume of natural gas that flows through the system and the price at which we are able to sell the residue natural gas and NGLs.

Certain of our gathering and/or processing agreements provide for monthly, annual or multi-year MVCs. Under these MVCs, our customers agree to ship and/or process a minimum volume of production on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us following the end of the contracted measurement period if its actual throughput volumes are less than its MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

We record customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering or processing fees in subsequent periods. We recognize customer obligations under their MVCs as revenue and contract assets when (i) we consider it remote that the customer will utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods; (ii) the customer incurs a shortfall in a contract with no banking mechanism or claw back provision; (iii) the customer’s banking mechanism has expired; or (iv) it is remote that the customer will use its unexercised right. In making this determination, we consider both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is 12 months or less. We classify deferred revenue as noncurrent for arrangements where the expiration of the right to utilize shortfall payments and our estimate of its potential utilization is more than 12 months.

Unit-Based Compensation. For awards of unit-based compensation, we determine a grant date fair value and recognize the related compensation expense in the statements of operations over the vesting period of the respective awards.

Income Taxes. As a partnership, we are generally not subject to federal and state income taxes, except as noted below. However, our unitholders are individually responsible for paying federal and state income taxes on their share of our taxable income. Net income or loss for GAAP purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and the GAAP basis of assets and liabilities and the taxable income allocation requirements under our Partnership Agreement. The aggregate difference in the basis of the

Partnership’s net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner’s tax attributes related to the Partnership.

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to a franchise tax (the "Texas Margin Tax"). The Texas Margin Tax has the characteristics of an income tax because it is

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determined by applying a tax rate to a tax base that considers both revenues and expenses. Our financial statements reflect provisions for these tax obligations.

Earnings or Loss Per Unit. We determine basic EPU by dividing the net income or loss that is attributed, in accordance with the net income and loss allocation provisions of our Partnership Agreement, to common limited partners under the two-class method, after deducting (i) any payment of IDRs, by the weighted-average number of limited partner units outstanding, (ii) the General Partner's approximate 2% interest in net income or loss, (iii) any net income or loss of contributed subsidiaries that is attributable to Summit Investments, (iv) the 1% noncontrolling interest in OpCo (for periods subsequent to the 2016 Drop Down and prior to 2018) and (v) net income attributable to Series A Preferred Units. Diluted EPU reflects the potential dilution that could occur if securities or other agreements to issue common units, such as unit-based compensation, were exercised, settled or converted into common units and included in the weighted-average number of units outstanding. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted EPU calculation, the impact is reflected by applying the treasury stock method. Pursuant to the closing of the Equity Restructuring Agreement, the IDRs and 2% general partner interest will be converted into 8,750,000 common units.

Comprehensive Income or Loss. Comprehensive income or loss is the same as net income or loss for all periods presented.

Environmental Matters. We are subject to various federal, state and local laws and regulations relating to the protection of the environment. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties or insurers are recorded as assets when their realization is assured beyond a reasonable doubt.

Recent Accounting Pronouncements. Accounting standard setters frequently issue new or revised accounting rules. We review new pronouncements to determine the impact, if any, on our financial statements. Accounting standards that have or could possibly have a material effect on our financial statements are discussed below.

Recently Adopted Accounting Pronouncements. We have recently adopted the following accounting pronouncements:

- ASU No. 2014-09 Revenue from Contracts with Customers ("Topic 606"). We adopted Topic 606 with a date of initial application of January 1, 2018. We applied Topic 606 by recognizing the cumulative effect of initially applying Topic 606 as an adjustment to the opening balance of partners' capital at January 1, 2018. The comparative information has not been adjusted and is reported under the accounting standards in effect for those periods.

For contracts where we perform gathering services and earn a per-unit fee which is recognized at a point in time, revenue is recognized over time as the service is performed and results in revenue recognition materially consistent with historical GAAP. In addition, our contracts generally contain forms of variable consideration, which will likely be constrained as the volumes are susceptible to factors outside of our control and influence. As a result of applying the constraint guidance, timing of revenue recognition will be materially consistent with historical GAAP.

Prior to the adoption of Topic 606, contributions in aid of construction were recognized as a reduction to our cost basis of property, plant and equipment and facility fees were recognized as revenue when the amounts were billed. Upon adoption of Topic 606, the contributions in aid of construction amounts previously received were capitalized to property, plant and equipment, net of any accumulated depreciation, and will be depreciated over the remaining useful lives. Any future contributions in aid of construction will be recognized as revenue over the then remaining term of the respective contract in accordance with Topic 606. Additionally, facility fees will be deferred and recognized over the remaining contract term.

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There are certain percent-of-proceeds contracts within our Williston Basin reportable segment where we previously recognized revenue for services provided to producers in gathering services and related fees. Such amounts which were previously presented gross in gathering services and related fees are presented net within cost of natural gas and NGLs. This change did not have any impact on our net income (loss), cash flows, or the amount we present as segment adjusted EBITDA.

For contracts containing MVC arrangements with banking mechanisms we previously deferred revenue. Under Topic 606, the recognition of revenue was accelerated. This acceleration totaled $16.7 million and is included in the Topic 606 day one adjustment amounts below in deferred revenue.

The cumulative effect of the changes made to our consolidated January 1, 2018 balance sheet for the adoption of Topic 606 was as follows:

| | Balance at December 31, 2017 | Adjustments Due to Topic 606 | Balance at January 1, 2018 |
|---|---|---|---|
| | (In thousands) | | |
| Assets | | | |
| Property, plant and equipment, net | $1,795,129 | $ 33,123 | $1,828,252 |
| Liabilities | | | |
| Deferred revenue, current | 4,000 | 6,088 | 10,088 |
| Deferred revenue, noncurrent | 12,707 | 22,821 | 35,528 |
| Partners' Capital (1) | 1,084,430 | 4,214 | 1,088,644 |

(1) Includes common limited partner capital and general partner interests.

Impact on financial statements

The following tables summarize the impact of Topic 606 adoption on our consolidated financial statements.

Consolidated balance sheet

| | December 31, 2018 | | |
|---|---|---|---|
| | As Reported | Balances Without Adoption of Topic 606 | Effect of Change Increase / (Decrease) |
| | (In thousands) | | |
| Assets | | | |

| | | | |
|---|---|---|---|
| Accounts receivable | $97,936 | $91,936 | $ 6,000 |
| Property, plant and equipment, net | 1,963,713 | 1,926,215 | 37,498 |
| | | | |
| Liabilities | | | |
| Deferred revenue, current | 11,467 | 4,071 | 7,396 |
| Deferred revenue, noncurrent | 39,504 | 8,938 | 30,566 |
| | | | |
| Partners' Capital (1) | 927,608 | 922,072 | 5,536 |

(1) Includes common limited partner capital and general partner interests.

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**Consolidated statement of operations**

| | Year ended December 31, 2018 | | |
|---|---|---|---|
| | As Reported | Balances Without Adoption of Topic 606 | Effect of Change Increase / (Decrease) |
| | (In thousands) | | |
| Revenues | | | |
| Gathering services and related fees | $344,616 | $351,589 | $ (6,973 ) |
| Costs and expenses | | | |
| Cost of natural gas and NGLs | 107,661 | 120,976 | (13,315 ) |
| Depreciation and amortization | 107,100 | 105,765 | 1,335 |

Consolidated statement of cash flows

| | Year ended December 31, 2018 | | |
|---|---|---|---|
| | As Reported | Balances Without Adoption of Topic 606 | Effect of Change Increase / (Decrease) |
| | (In thousands) | | |
| Cash flows from operating activities: | | | |
| Net income | $42,351 | $37,344 | $ 5,007 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 106,767 | 105,432 | 1,335 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | (21,535 ) | (15,535 ) | (6,000 ) |
| Deferred revenue, net | 5,355 | 5,697 | (342 ) |

- ASU No. 2017-04 Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment ("ASU 2017-04"). ASU 2017-04 simplifies the subsequent measurement of goodwill by, among other things, eliminating step two from the goodwill impairment test. ASU 2017-04 is effective for public companies for fiscal years beginning after December 15, 2019 and it specifies the amendments in ASU 2017-04 should be applied on a prospective basis. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We adopted the provisions of ASU 2017-04 effective January 1, 2018. The adoption of this standard had no impact on our consolidated financial statements.

Accounting Pronouncements Pending Adoption. We have not yet adopted the following accounting pronouncements as of December 31, 2018:

- ASU No. 2016-02 Leases (Topic 842) ("ASU 2016-02"). ASU 2016-02 requires that lessees recognize all leases on the balance sheet, with the exception of short-term leases. A lease liability will be recorded for the obligation of a lessee to make lease payments arising from a lease. A right-of-use (“ROU”) asset will be recorded which represents the lessee’s right to use, or to control the use of, a specified asset for a lease term. ASU 2016-02 is effective for public companies for fiscal years beginning after December 15, 2018, and requires the modified retrospective approach for transition.

We expect to utilize certain practical expedients including (i) not being required to reassess whether any expired or existing contracts are or contain leases; (ii) not being required to reassess the lease classification for any expired or existing leases (that is, all existing leases that were classified as operating leases in accordance with Topic 840 will be classified as operating leases, and all existing leases that were classified as capital leases in accordance with Topic 840 will be classified as finance leases); and (iii) not being required to reassess initial direct costs for any existing leases.

We adopted ASU 2016-02 on January 1, 2019. We will recognize a ROU asset and a corresponding lease liability based on the present value of such obligations. Based on current estimates, the total ROU assets we will recognize under ASU 2016-02 will account for less than 0.5% of total consolidated assets and the corresponding lease liabilities will account for less than 0.5% of total consolidated liabilities. We will also provide additional disclosures around the nature of the leasing activities beginning in our Form 10-Q for the three months ended March 31, 2019. These include additional qualitative disclosures, such as a general description of leases, and quantitative disclosures, such as lease costs, weighted average remaining lease term and weighted average discount rate.

- ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842 ("ASU 2018-01"). ASU 2018-01 provides an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under the current lease guidance in Topic 840. Upon adoption of Topic 842, an entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date the entity adopts Topic 842. We expect to adopt the optional transition practical expedient of ASU 2018-01 effective January 1, 2019.
- ASU No. 2018-13 Fair Value Measurement ("ASU 2018-13"). ASU 2018-13 updates the disclosure requirements on fair value measurements including new disclosures for the changes in unrealized gains and losses for the period included in other comprehensive income for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. ASU 2018-13 modifies existing disclosures including clarifying the measurement uncertainty disclosure. ASU 2018-13 removes certain existing disclosure requirements including the amount and reasons for transfers between Level 1 and Level 2 fair value measurements and the policy for the timing of transfer between levels. We are currently evaluating the provisions of ASU 2018-13 to determine its impact on our financial statements and related disclosures and will adopt its provisions effective January 1, 2020.

3. REVENUE

The majority of our revenue is derived from long-term, fee-based contracts with original terms of up to 25 years. We account for revenue in accordance with Topic 606, which we adopted on January 1, 2018, using the modified retrospective method. See Note 2 for further discussion of the adoption, including the impact on our consolidated financial statements.

The transaction price in our contracts is primarily based on the volume of natural gas, crude oil or produced water transferred by our gathering systems to the customer's agreed upon delivery point multiplied by the contractual rate. For contracts that include MVCs, variable consideration up to the MVC will be included in the transaction price. For contracts that do not include MVCs, we do not estimate variable consideration because the performance obligations are completed and settled on a daily basis. For contracts containing noncash consideration such as fuel received in-kind, we measure the transaction price at the point of sale when the volume, mix and market price of the commodities are known.

We have contracts with MVCs that are variable and constrained. Contracts with MVCs are reviewed on a quarterly basis and adjustments to those estimates are made during each respective reporting period, if necessary.

The transaction price is allocated if the contract contains more than one performance obligation such as contracts that include MVCs. The transaction price allocated is based on the MVC for the applicable measurement period.

Performance obligations. The majority of our contracts have a single performance obligation which is either to provide gathering services (an integrated service) or sell natural gas, NGLs and condensate, which are both satisfied when the related natural gas, crude oil and produced water are received and transferred to an agreed upon delivery point. We also have certain contracts with multiple performance obligations. They include an option for the customer to acquire additional services such as contracts containing MVCs. These performance obligations would also be satisfied when the related natural gas, crude oil and produced water are received and transferred to an agreed upon delivery point. In these instances, we allocate the contract's transaction price to each performance obligation using our best estimate of the standalone selling price of each service in the contract.

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Performance obligations for gathering services are generally satisfied over time. We utilize either an output method (i.e., measure of progress) for guaranteed, stand-ready service contracts or an asset / system delivery time estimate for non-guaranteed, as-available service contracts.

Performance obligations for the sale of natural gas, NGLs and condensate are satisfied at a point in time. There are no significant judgments for these transactions because the customer obtains control based on an agreed upon delivery point.

Certain of our gathering and/or processing agreements provide for monthly, annual or multi-year MVCs. Under these MVCs, our customers agree to ship and/or process a minimum volume of production on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contracted measurement period if its actual throughput volumes are less than its MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

We recognize customer obligations under their MVCs as revenue and contract assets when (i) we consider it remote that the customer will utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods; (ii) the customer incurs a shortfall in a contract with no banking mechanism or claw back provision; (iii) the customer’s banking mechanism has expired; or (iv) it is remote that the customer will use its unexercised right.

Our services are typically billed on a monthly basis and we do not offer extended payment terms. We do not have contracts with financing components.

The following table presents estimated revenue expected to be recognized over the remaining contract period related to performance obligations that are unsatisfied and are comprised of estimated MVC shortfall payments.

We applied the practical expedient in paragraph 606-10-50-14 of Topic 606 for certain arrangements that we consider optional purchases (i.e., there is no enforceable obligation for the customer to make purchases) and those amounts are excluded from the table.

| | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter |
|---|---|---|---|---|---|---|
| | (In thousands) | | | | | |
| Gathering services and related fees | $126,006 | $122,429 | $100,070 | $83,626 | $70,923 | $112,462 |

Revenue by Category. In the following table, revenue is disaggregated by geographic area and major products and services. For more detailed information about reportable segments, see Note 4.

Reportable Segments
Year ended December 31, 2018

| | Utica Shale | Williston Basin | DJ Basin | Permian Basin | Piceance Basin | Barnett Shale | Marcellus Shale | Total reportable segments | All other segments | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | (In thousands) | | | | | | | | | |
| Major products / services lines | | | | | | | | | | |
| Gathering services and related fees | $35,233 | $79,606 | $11,251 | $115 | $135,810 | $59,030 | $29,573 | $350,618 | $(6,002 ) | $344,616 |
| Natural gas, NGLs and condensate sales | — | 31,840 | 371 | 843 | 14,800 | 2,523 | — | 50,377 | 84,457 | 134,834 |
| Other revenues | — | 12,204 | 3,672 | — | 4,909 | 6,712 | — | 27,497 | (294 ) | 27,203 |
| Total | $35,233 | $123,650 | $15,294 | $958 | $155,519 | $68,265 | $29,573 | $428,492 | $78,161 | $506,653 |

Contract balances. Contract assets relate to our rights to consideration for work completed but not billed at the reporting date and consist of the estimated MVC shortfall payments expected from our customers and unbilled activity associated with contributions in aid of construction. Contract assets are transferred to trade receivables when the

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rights become unconditional. The following table provides information about contract assets from contracts with customers:

| | December 31, 2018 (In thousands) |
|---|---|
| Contract assets, December 31, 2017 | $ — |
| Additions | 26,403 |
| Transfers out | (17,648 ) |
| Contract assets, December 31, 2018 | $ 8,755 |

As of December 31, 2018, receivables with customers totaled $82.9 million and contract assets totaled $8.8 million which were included in the accounts receivable caption on the consolidated balance sheet.

Contract liabilities (deferred revenue) relate to the advance consideration received from customers primarily for contributions in aid of construction. We recognize contract liabilities under these arrangements in revenue over the contract period. For the year ended December 31, 2018, we recognized $10.8 million of gathering services and related fees which was included in the contract liability balance as of the beginning of the period. See Note 9 for additional details.

4. SEGMENT INFORMATION

We evaluate our business operations each reporting period to determine whether any of our operating segments in which we internally report financial information are considered significant and would require us to separately disclose certain segment financial information in our external reporting. As a result of our evaluation, during the fourth quarter of 2018, we determined that the DJ Basin natural gas gathering and processing system, previously reported within the Piceance/DJ Basins reportable segment, is expected to be a significant operating segment in future reporting periods. This determination was based on, among other things, the development of a new 60 MMcf/d processing plant that is expected to be operational in 2019, which will increase volume throughput beginning in 2019. In addition, we determined the Permian Basin natural gas gathering and processing system, which was commissioned in the fourth quarter of 2018, is expected to be a significant operating segment in future reporting periods. As such, we modified our current segments in the fourth quarter of 2018 such that the DJ Basin reportable segment includes the Niobrara G&P system and the Permian Basin reportable segment includes the Summit Permian natural gas gathering and processing system. For the year ended December 31, 2018, we have disclosed the required segment information for Niobrara G&P and Summit Permian and the periods prior have been recast to reflect this change.

As of December 31, 2018, our reportable segments are:

- the Utica Shale, which is served by Summit Utica;
- Ohio Gathering, which includes our ownership interest in OGC and OCC;
- the Williston Basin, which is served by Polar and Divide, Tioga Midstream and Bison Midstream;
- the DJ Basin, which is served by Niobrara G&P;

- the Permian Basin, which is served by Summit Permian;
- the Piceance Basin, which is served by Grand River;
- the Barnett Shale, which is served by DFW Midstream; and
- the Marcellus Shale, which is served by Mountaineer Midstream.

Each of our reportable segments provides midstream services in a specific geographic area. Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations.

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The Ohio Gathering reportable segment includes our investment in OGC and OCC. Income or loss from equity method investees, as reflected on the statements of operations, solely relates to Ohio Gathering and is recognized and disclosed on a one-month lag (see Note 8).

Corporate and Other represents those results that are: (i) not specifically attributable to a reportable segment; (ii) not individually reportable; or (iii) that have not been allocated to our reportable segments for the purpose of evaluating their performance, including certain general and administrative expense items, natural gas and crude oil marketing services and transaction costs.

Assets by reportable segment follow.

| | December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Assets: | | | |
| Utica Shale | $207,357 | $212,311 | $199,392 |
| Ohio Gathering | 649,250 | 690,485 | 707,415 |
| Williston Basin | 526,819 | 512,860 | 724,084 |
| DJ Basin | 166,580 | 79,438 | 72,494 |
| Permian Basin | 145,702 | 57,590 | — |
| Piceance Basin | 699,638 | 719,284 | 770,946 |
| Barnett Shale | 376,564 | 383,306 | 404,314 |
| Marcellus Shale | 208,790 | 217,362 | 224,709 |
| Total reportable segment assets | 2,980,700 | 2,872,636 | 3,103,354 |
| Corporate and Other | 44,181 | 22,406 | 12,294 |
| Eliminations | (4,319) | (249) | (469) |
| Total assets | $3,020,562 | $2,894,793 | $3,115,179 |

Revenues by reportable segment follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Revenues (1): | | | |
| Utica Shale | $35,233 | $38,907 | $24,263 |
| Williston Basin | 123,650 | 161,503 | 122,174 |
| DJ Basin | 15,294 | 11,860 | 8,439 |
| Permian Basin | 958 | — | — |
| Piceance Basin | 155,519 | 154,893 | 141,464 |
| Barnett Shale | 68,265 | 71,667 | 79,956 |
| Marcellus Shale | 29,573 | 30,394 | 26,111 |
| Total reportable segments revenue | 428,492 | 469,224 | 402,407 |
| Corporate and Other | 88,286 | 26,446 | 412 |
| Eliminations | (10,125) | (6,929) | (457) |
| Total revenues | $506,653 | $488,741 | $402,362 |

(1) Excludes revenues earned by Ohio Gathering due to equity method accounting.

Counterparties accounting for more than 10% of total revenues were as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Percentage of total revenues (1)(2): | | | |
| Counterparty A - Piceance Basin | * | * | 14 % |
| Counterparty B - Williston Basin | * | 13 % | * |
| Counterparty C - Piceance Basin | 10% | * | * |

(1) Includes recognition of revenue that was previously deferred in connection with minimum volume commitments (see Note 9).

(2) Excludes revenues earned by Ohio Gathering due to equity method accounting.

* Less than 10%

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Depreciation and amortization, including the amortization expense associated with our favorable and unfavorable gas gathering contracts as reported in other revenues, by reportable segment follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Depreciation and amortization (1): | | | |
| Utica Shale | $7,672 | $7,009 | $4,331 |
| Williston Basin | 22,642 | 33,772 | 33,676 |
| DJ Basin | 3,133 | 2,636 | 2,524 |
| Permian Basin | 243 | — | — |
| Piceance Basin | 46,919 | 46,289 | 46,616 |
| Barnett Shale (2) | 15,325 | 15,001 | 16,093 |
| Marcellus Shale | 9,090 | 9,047 | 8,841 |
| Total reportable segment depreciation and amortization | 105,024 | 113,754 | 112,081 |
| Corporate and Other | 1,743 | 1,118 | 580 |
| Total depreciation and amortization | $106,767 | $114,872 | $112,661 |

(1) Excludes depreciation and amortization recognized by Ohio Gathering due to equity method accounting.

(2) Includes the amortization expense associated with our favorable and unfavorable gas gathering contracts as reported in other revenues.

Cash paid for capital expenditures by reportable segment follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Cash paid for capital expenditures (1): | | | |
| Utica Shale | $5,719 | $22,921 | $78,708 |
| Williston Basin | 25,202 | 17,309 | 31,541 |
| DJ Basin | 64,920 | 7,150 | 5,807 |
| Permian Basin | 83,823 | 56,020 | — |
| Piceance Basin | 7,887 | 16,564 | 19,912 |
| Barnett Shale | 1,370 | 569 | 3,910 |
| Marcellus Shale | 1,030 | 641 | 1,173 |
| Total reportable segment capital expenditures | 189,951 | 121,174 | 141,051 |
| Corporate and Other | 10,635 | 3,041 | 1,668 |
| Total cash paid for capital expenditures | $200,586 | $124,215 | $142,719 |

(1) Excludes cash paid for capital expenditures by Ohio Gathering due to equity method accounting.

During the year ended December 31, 2018, Corporate and Other included cash paid of $3.3 million for corporate purposes; the remainder represents capital expenditures for the Double E Pipeline Project relating to the Summit Permian Transmission expansion.

We assess the performance of our reportable segments based on segment adjusted EBITDA. We define segment adjusted EBITDA as total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) our proportional adjusted EBITDA for equity method investees, (iii) depreciation and amortization, (iv) adjustments related to MVC shortfall payments, (v) adjustments related to capital reimbursement activity, (vi) unit-based and noncash compensation, (vii) change in the Deferred Purchase Price Obligation fair value, (viii) early extinguishment of debt expense, (ix) impairments and (x) other noncash expenses or losses, less other noncash income or gains. We define proportional adjusted EBITDA for our equity method investees as the product of (i) total revenues less total expenses, excluding impairments and other noncash income or expense items and (ii) amortization for deferred contract costs; multiplied by our ownership interest in Ohio Gathering during the respective period.

For the purpose of evaluating segment performance, we exclude the effect of Corporate and Other revenues and expenses, such as certain general and administrative expenses (including compensation-related expenses and professional services fees), natural gas and crude oil marketing services, transaction costs, interest expense, change in the Deferred Purchase Price Obligation fair value, early extinguishment of debt expense and income tax expense or benefit from segment adjusted EBITDA.

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Segment adjusted EBITDA by reportable segment follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Reportable segment adjusted EBITDA | | | |
| Utica Shale | $30,285 | $34,011 | $21,035 |
| Ohio Gathering | 39,969 | 41,246 | 45,602 |
| Williston Basin | 76,701 | 66,413 | 79,475 |
| DJ Basin | 7,558 | 6,624 | 3,681 |
| Permian Basin | (1,200 ) | — | — |
| Piceance Basin | 111,042 | 111,113 | 105,560 |
| Barnett Shale | 43,268 | 46,232 | 54,634 |
| Marcellus Shale | 24,267 | 23,888 | 19,203 |
| Total of reportable segments' measures of profit or loss | $331,890 | $329,527 | $329,190 |

A reconciliation of income or loss before income taxes and income or loss from equity method investees to total of reportable segments' measures of profit or loss follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Reconciliation of income (loss) before income taxes and loss from equity method investees to total of reportable segments' measures of profit: | | | |
| Income (loss) before income taxes and loss from equity method investees | $53,272 | $88,614 | $(7,768 ) |
| Add: | | | |
| Corporate and Other | 38,917 | 39,140 | 37,589 |
| Interest expense | 60,535 | 68,131 | 63,810 |
| Early extinguishment of debt | — | 22,039 | — |
| Deferred Purchase Price Obligation | 20,975 | (200,322 ) | 55,854 |
| Depreciation and amortization | 106,767 | 114,872 | 112,661 |
| Proportional adjusted EBITDA for equity method investees | 39,969 | 41,246 | 45,602 |
| Adjustments related to MVC shortfall payments | (3,632 ) | (41,373 ) | 11,600 |
| Adjustments related to capital reimbursement activity | (427 ) | — | — |
| Unit-based and noncash compensation | 8,328 | 7,951 | 7,985 |

| | | | |
|---|---|---|---|
| Loss on asset sales, net | — | 527 | 93 |
| Long-lived asset impairment | 7,186 | 188,702 | 1,764 |
| Total of reportable segments' measures of profit | $331,890 | $329,527 | $329,190 |

For the year ended December 31, 2018, in accordance with Topic 606, adjustments related to MVC shortfall payments are recognized in gathering services and related fees (see Note 3).

In accordance with Topic 606, contributions in aid of construction are recognized over the remaining term of the respective contract. We include adjustments related to capital reimbursement activity in our calculation of segment adjusted EBITDA to account for revenue recognized from contributions in aid of construction.

For the years ended December 31, 2017 and 2016, we included adjustments related to MVC shortfall payments in our calculation of segment adjusted EBITDA to account for (i) the net increases or decreases in deferred revenue for MVC shortfall payments and (ii) our inclusion of expected annual or multi-year MVC shortfall payments. With respect to the impact of a net change in deferred revenue for MVC shortfall payments, we treated increases in deferred revenue balances as a favorable adjustment to segment adjusted EBITDA, while decreases in deferred revenue balances were treated as an unfavorable adjustment to segment adjusted EBITDA. We also included a proportional amount of any historical and expected MVC shortfall payments in each quarter prior to the quarter in which we actually recognize the shortfall payment.

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Adjustments related to MVC shortfall payments by reportable segment follow.

| | Year ended December 31, 2018 | | | |
|---|---|---|---|---|
| | Williston Basin | Piceance Basin | Barnett Shale | Total |
| | (In thousands) | | | |
| Adjustments related to MVC shortfall payments: | | | | |
| Net change in deferred revenue for MVC shortfall payments | $— | $ — | $— | $— |
| Expected MVC shortfall adjustments | — | 10 | (3,642) | (3,632) |
| Total adjustments related to MVC shortfall payments | $— | $ 10 | $(3,642) | $(3,632) |

| | Year ended December 31, 2017 | | | |
|---|---|---|---|---|
| | Williston Basin | Piceance Basin | Barnett Shale | Total |
| | (In thousands) | | | |
| Adjustments related to MVC shortfall payments: | | | | |
| Net change in deferred revenue for MVC shortfall payments | $(37,693) | $(3,065) | $— | $(40,758) |
| Expected MVC shortfall adjustments | — | (3) | (612) | (615) |
| Total adjustments related to MVC shortfall payments | $(37,693) | $(3,068) | $(612) | $(41,373) |

| | Year Ended December 31, 2016 | | | |
|---|---|---|---|---|
| | Williston Basin | Piceance Basin | Barnett Shale | Total |
| | (In thousands) | | | |
| Adjustments related to MVC shortfall payments: | | | | |
| Net change in deferred revenue for MVC shortfall payments | $8,691 | $ 3,288 | $ (677) | $11,302 |
| Expected MVC shortfall adjustments | — | (317) | 615 | 298 |
| Total adjustments related to MVC shortfall payments | $8,691 | $ 2,971 | $ (62) | $11,600 |

5. PROPERTY, PLANT AND EQUIPMENT, NET

Details on property, plant and equipment follow.

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| | (In thousands) | |
| Gathering and processing systems and related equipment | $2,155,325 | $ 1,973,722 |
| Construction in progress | 137,920 | 78,850 |
| Land and line fill | 11,748 | 11,735 |
| Other | 45,853 | 40,262 |
| Total | 2,350,846 | 2,104,569 |
| Less accumulated depreciation | 387,133 | 309,440 |
| Property, plant and equipment, net | $1,963,713 | $ 1,795,129 |

During 2018, 2017 and 2016, we identified certain events, facts and circumstances which indicated that certain of our property, plant and equipment could be impaired. As such, we reviewed the assets that had been identified as potentially impaired and estimated the fair value of the identified property, plant and equipment using a market-based approach.

In December 2018, in connection with certain strategic initiatives, we performed a recoverability assessment of certain assets within the Williston Basin reporting segment. Based on the results, we concluded that the carrying value of certain long-lived assets related to the Tioga Midstream system within the Williston Basin were not fully recoverable. We recorded an impairment charge of $3.9 million related to these assets after comparing the fair value of the long-lived assets to their carrying values. In addition, we reviewed the other assets that had been identified as potentially impaired and recognized the long-lived asset impairments in the table below.

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In December 2017, in connection with certain strategic initiatives, we performed a financial review of certain assets within the Williston Basin reporting segment. This resulted in a triggering event that required us to perform a recoverability test. Based on the results of the test, we concluded that the carrying value of certain long-lived assets related to the Bison Midstream system within the Williston Basin were not fully recoverable. We recorded an impairment charge of $101.9 million related to these assets after comparing the fair value of the long-lived assets to their carrying values. See Note 6 for additional details.

During 2018, 2017 and 2016, we recognized the following long-lived asset impairments, by segment.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Long-lived asset impairment: | | | |
| Williston Basin | $3,972 | $101,961 | $569 |
| Piceance Basin | 1,004 | 697 | — |
| DJ Basin | 9 | — | — |
| Barnett Shale | — | — | 1,195 |
| Utica Shale | 1,440 | 878 | — |
| Permian Basin | 761 | — | — |

Our impairment determinations, in the context of these reviews, involved significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these estimates are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

Depreciation expense and capitalized interest follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Depreciation expense | $74,511 | $75,120 | $70,770 |
| Capitalized interest | 8,497 | 2,579 | 3,709 |

6. AMORTIZING INTANGIBLE ASSETS AND UNFAVORABLE GAS GATHERING CONTRACT

Details regarding our intangible assets and the unfavorable gas gathering contract (included in other noncurrent liabilities prior to 2018), all of which are subject to amortization, follow.

| | December 31, 2018 | | |
|---|---|---|---|
| | Gross carrying amount | Accumulated amortization | Net |
| | (In thousands) | | |
| Favorable gas gathering contracts | $24,195 | $ (13,905 ) | $10,290 |

| | | | |
|---|---|---|---|
| Contract intangibles | 278,448 | (143,962 ) | 134,486 |
| Rights-of-way | 166,209 | (37,569 ) | 128,640 |
| Total intangible assets | $468,852 | $ (195,436 ) | $273,416 |
| | | | |
| Unfavorable gas gathering contract | $10,962 | $ (10,962 ) | $— |

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| | December 31, 2017 | | |
|---|---|---|---|
| | Gross carrying amount | Accumulated amortization | Net |
| | (In thousands) | | |
| Favorable gas gathering contracts | $24,195 | $ (12,350 ) | $11,845 |
| Contract intangibles | 278,448 | (117,821 ) | 160,627 |
| Rights-of-way | 159,986 | (31,113 ) | 128,873 |
| Total intangible assets | $462,629 | $ (161,284 ) | $301,345 |
| | | | |
| Unfavorable gas gathering contract | $10,962 | $ (9,074 ) | $1,888 |

In December 2017, in connection with certain strategic initiatives, we evaluated certain long-lived assets relating to the Bison Midstream system within the Williston Basin reporting segment (see Note 5). In connection with this evaluation, we evaluated the related intangible assets associated therewith for impairment consisting of contract intangible assets and rights-of-way intangible assets. We concluded the contract intangible assets were also impaired and, as a result, we recorded an impairment charge of $85.2 million.

We recognized amortization expense in other revenues as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Amortization expense – favorable gas gathering contracts | $(1,555 ) | $(1,555 ) | $(1,261 ) |
| Amortization expense – unfavorable gas gathering contract | 1,888 | 2,158 | 839 |

We recognized amortization expense in costs and expenses as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Amortization expense – contract intangibles | $26,141 | $34,202 | $35,416 |
| Amortization expense – rights-of-way | 6,448 | 6,153 | 6,053 |

The estimated aggregate annual amortization expected to be recognized for as of December 31, 2018 for each of the five succeeding fiscal years follows.

| | Intangible assets (In thousands) |
|---|---|
| 2019 | $ 32,422 |
| 2020 | 32,246 |
| 2021 | 28,554 |
| 2022 | 25,487 |
| 2023 | 25,433 |

7. GOODWILL

Goodwill for the periods presented of $16.2 million is related to the acquisition of the Mountaineer Midstream system in 2013.

Accumulated goodwill impairments by reportable segment for those reporting units that have previously recognized goodwill follow.

| | As of December 31, 2018, 2017, 2016 (In thousands) |
|---|---|
| Accumulated goodwill impairment: | |
| Piceance Basin | $ 45,478 |
| Williston Basin | 257,572 |
| Total accumulated goodwill impairment | $ 303,050 |

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As discussed in Note 2, we evaluate goodwill for impairment annually on September 30 and whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value, including goodwill.

We performed our annual goodwill impairment testing for the Mountaineer Midstream reporting unit as of September 30, 2018 using a combination of the income and market approaches. We determined that its fair value substantially exceeded its carrying value, including goodwill.

We had no impairments of goodwill for the years ended December 31, 2018 and 2017.

Fair Value Measurement. Our impairment determinations, in the context of (i) our annual impairment evaluations and (ii) our other-than-annual impairment evaluations involved significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the valuations. As such, the fair value measurements utilized within these models are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

8. EQUITY METHOD INVESTMENTS

Ohio Gathering owns, operates and is currently developing midstream infrastructure consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate stabilization facility in the Utica Shale in southeastern Ohio. Ohio Gathering provides gathering services pursuant to primarily long-term, fee-based gathering agreements, which include acreage dedications.

Our initial investment in Ohio Gathering in 2014 included a $190.0 million payment to acquire a 1% interest from a third party, which included an option to increase our ownership to 40%, as well as a series of contributions directly to Ohio Gathering in 2014, which increased our ownership to 40%. Concurrent with and subsequent to the exercise of the option, the non-affiliated owners have retained their respective 60% ownership interest in Ohio Gathering (the "Non-affiliated Owners").

We account for our ownership interests in Ohio Gathering as an equity method investment because we have joint control with the Non-affiliated Owners, which gives us significant influence.

We recognize the $190.0 million paid for the initial 1% interest as an investment in Ohio Gathering at inception. In addition, Ohio Gathering assigned a value of $7.5 million to the exercise option, which it ultimately attributed to our capital account. Neither of the aforementioned transactions involved a flow of funds to or from Ohio Gathering. As such, they created a basis difference between our recorded investment in equity method investees and the amount attributed to us by Ohio Gathering within its financial statements. We are amortizing these basis differences over the weighted-average remaining life of the contracts underlying Ohio Gathering's operations.

In December 2018 and 2017, asset impairments were recognized by Ohio Gathering. In addition, Ohio Gathering was involved in legal proceedings relating to a dispute regarding pipeline right of way rights and associated trespass claims that took place prior to December 31, 2018. Ohio Gathering received a judgment on those proceedings in January 2019 and recorded an estimate of the legal exposure as of December 31, 2018. Although we recognize activity for Ohio Gathering on a one-month lag, we recorded the asset impairments and legal contingency in our results of operations for the year ending December 31, 2018 and asset impairments for the year ending December 31, 2017 because the information was available to us. We recorded our 40% share of the asset impairments and legal contingency amounting to $7.7 million in 2018 and asset impairments of $1.4 million in 2017 in loss from equity method investees in the consolidated statements of operations.

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A reconciliation of our 40% ownership interest in Ohio Gathering to our investment per Ohio Gathering's books and records follows (in thousands).

| | 2018 | 2017 |
|---|---|---|
| | (In thousands) | |
| Investment in equity method investees, December 31 | $649,250 | $690,485 |
| December cash distributions | 2,736 | 4,032 |
| December cash contributions | — | (3,932 ) |
| Impairment loss | 5,652 | 1,383 |
| Legal contingency | 2,040 | — |
| Basis difference | (116,832 ) | (130,184 ) |
| Investment in equity method investees, net of basis difference, November 30 | $542,846 | $561,784 |

Summarized balance sheet information for OGC and OCC follows (amounts represent 100% of investee financial information).

| | November 30, 2018 | | November 30, 2017 | |
|---|---|---|---|---|
| | OGC | OCC | OGC | OCC |
| | (In thousands) | | | |
| Current assets | $37,403 | $3,716 | $34,383 | $3,650 |
| Noncurrent assets | 1,262,253 | 27,203 | 1,319,448 | 29,156 |
| Total assets | $1,299,656 | $30,919 | $1,353,831 | $32,806 |
| | | | | |
| Current liabilities | $19,903 | $3,912 | $10,882 | $3,382 |
| Noncurrent liabilities | 3,688 | 8,807 | 3,272 | 11,715 |
| Total liabilities | $23,591 | $12,719 | $14,154 | $15,097 |

Summarized statements of operations information for OGC and OCC follow (amounts represent 100% of investee financial information).

| | Twelve months ended November 30, 2018 | | Twelve months ended November 30, 2017 | | Twelve months ended November 30, 2016 | |
|---|---|---|---|---|---|---|
| | OGC | OCC | OGC | OCC | OGC | OCC |
| | (In thousands) | | | | | |
| Total revenues | $142,398 | $10,177 | $140,679 | $8,607 | $148,662 | $15,791 |
| Total operating expenses | 136,722 | 9,053 | 111,897 | 8,298 | 96,647 | 111,528 |
| Net income (loss) | 5,670 | 498 | 28,785 | (907 ) | 52,009 | (94,230 ) |

9. DEFERRED REVENUE

Certain of our gathering and/or processing agreements provide for monthly, annual or multi-year MVCs. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped and/or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable gathering or processing fee.

Many of our gas gathering agreements contain provisions that can reduce or delay the cash flows that we expect to receive from our MVCs to the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period. These provisions include the following:

- To the extent that a customer's throughput volumes are less than its MVC for the applicable period and the customer makes a shortfall payment, it may be entitled to an offset in one or more subsequent periods to the extent that its throughput volumes in subsequent periods exceed its MVC for those periods. In such a situation, we would not receive gathering fees on throughput in excess of that customer's MVC (depending on the terms of the specific gas gathering agreement) to the extent that the customer had made a shortfall payment with respect to one or more preceding measurement periods (as applicable).

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- To the extent that a customer's throughput volumes exceed its MVC in the applicable contracted measurement period, it may be entitled to apply the excess throughput against its aggregate MVC, thereby reducing the period for which its annual MVC applies. As a result of this mechanism, the weighted-average remaining period for which our MVCs apply will be less than the weighted-average of the original stated contract terms of our MVCs.
- To the extent that certain of our customers' throughput volumes exceed its MVC for the applicable period, there is a crediting mechanism that allows the customer to build a bank of credits that it can utilize in the future to reduce shortfall payments owed in subsequent periods, subject to expiration if there is no shortfall in subsequent periods. The period over which this credit bank can be applied to future shortfall payments varies, depending on the particular gas gathering agreement.

A rollforward of current deferred revenue follows.

| | Utica Shale | Williston Basin | DJ Basin | Piceance Basin | Barnett Shale | Marcellus Shale | Total current |
|---|---|---|---|---|---|---|---|
| | (In thousands) | | | | | | |
| Current deferred revenue, January 1, 2017 | $— | $— | $— | $— | $— | $ — | $— |
| Additions | — | — | — | 18,294 | — | — | 18,294 |
| Less revenue recognized | — | — | — | 14,294 | — | — | 14,294 |
| Current deferred revenue, December 31, 2017, as reported | — | — | — | 4,000 | — | — | 4,000 |
| Net impact of Topic 606 day 1 adoption | 18 | 1,017 | 358 | 3,038 | 1,619 | 38 | 6,088 |
| Current deferred revenue, January 1, 2018 | 18 | 1,017 | 358 | 7,038 | 1,619 | 38 | 10,088 |
| Additions | 18 | 1,744 | 943 | 21,955 | 1,651 | 96 | 26,407 |
| Less revenue recognized | 18 | 1,347 | 562 | 21,377 | 1,628 | 96 | 25,028 |
| Current deferred revenue, December 31, 2018 | $18 | $ 1,414 | $739 | $7,616 | $1,642 | $ 38 | $11,467 |

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A rollforward of noncurrent deferred revenue follows.

| | Utica Shale | Williston Basin | DJ Basin | Piceance Basin | Barnett Shale | Marcellus Shale | Total noncurrent |
|---|---|---|---|---|---|---|---|
| | (In thousands) | | | | | | |
| Noncurrent deferred, revenue, January 1, 2017 | $— | $37,693 | $— | $19,772 | $— | $ — | $ 57,465 |
| Less revenue recognized | — | 37,693 | — | 3,065 | — | | 40,758 |
| Less reclassification to current deferred revenue | — | — | — | 4,000 | — | — | 4,000 |
| Noncurrent deferred revenue, December 31, 2017, as reported | — | — | — | 12,707 | — | — | 12,707 |
| Net impact of Topic 606 day 1 adoption | 39 | 4,215 | 4,505 | 5,512 | 8,217 | 333 | 22,821 |
| Noncurrent deferred revenue, January 1, 2018 | 39 | 4,215 | 4,505 | 18,219 | 8,217 | 333 | 35,528 |
| Additions | — | 1,851 | 3,720 | 7,869 | 3,062 | — | 16,502 |
| Less reclassification to current deferred revenue | 18 | 1,673 | 941 | 8,146 | 1,651 | 97 | 12,526 |
| Noncurrent deferred revenue, December 31, 2018 | $21 | $4,393 | $7,284 | $17,942 | $9,628 | $ 236 | $ 39,504 |

During the first quarter of 2017, we amended an agreement with one of our key customers in the Williston Basin segment. Based on our review of the amendment and original contract, we determined this was not a material modification to the contract and that we had no further performance obligations in regards to the previously-made MVC payments. As a result, we recognized previously deferred revenue of $37.7 million as gathering services and related fees during the first quarter of 2017.

10. DEBT

Debt consisted of the following:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| | (In thousands) | |
| Summit Holdings' variable rate senior secured Revolving Credit Facility (5.03% at December 31, 2018 and 4.07% at December 31, 2017) due May 2022 | $466,000 | $ 261,000 |
| Summit Holdings' 5.5% senior unsecured notes due August 2022 | 300,000 | 300,000 |
| Less unamortized debt issuance costs (1) | (2,362) | (2,910) |
| Summit Holdings' 5.75% senior unsecured notes due April 2025 | 500,000 | 500,000 |
| Less unamortized debt issuance costs (1) | (5,907) | (6,898) |
| Total long-term debt | $1,257,731 | $ 1,051,192 |

__________

(1) Issuance costs are being amortized over the life of the notes.

The aggregate amount of debt maturing during each of the years after December 31, 2018 are as follow (in thousands):

| | |
|---|---|
| 2019 | $— |
| 2020 | — |
| 2021 | — |
| 2022 | 766,000 |
| 2023 | — |
| Thereafter | 500,000 |
| Total long-term debt | $1,266,000 |

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Revolving Credit Facility. Summit Holdings has a senior secured Revolving Credit Facility which allows for revolving loans, letters of credit and swingline loans. The Revolving Credit Facility has a $1.25 billion borrowing capacity, matures in May 2022, and includes a $250.0 million accordion feature. Bison Midstream and its subsidiaries, Grand River and its subsidiary, DFW Midstream, Summit Marketing, Summit Permian, Permian Finance, Summit Niobrara, OpCo, Summit Utica, Meadowlark Midstream, Tioga Midstream and SMLP fully and unconditionally and jointly and severally guarantee, and pledge substantially all of their assets in support of, the indebtedness outstanding under the Revolving Credit Facility.

In May 2017, Summit Holdings amended and restated its Revolving Credit Facility with a third amended and restated credit agreement which: (i) maintained the Revolving Credit Facility commitments of $1.25 billion, (ii) extended the maturity from November 2018 to May 2022, (iii) included a $250.0 million accordion feature, (iv) maintained the same leverage-based pricing and commitment fee grid, (v) increased the maximum permitted total leverage ratio, as defined in the credit agreement, from 5.00 to 1.00 to 5.50 to 1.00 and (vi) included a maximum permitted senior secured leverage ratio, as defined in the credit agreement, of 3.75 to 1.00.

Borrowings under the Revolving Credit Facility bear interest, at the election of Summit Holdings, at a rate based on the alternate base rate (as defined in the credit agreement) plus an applicable margin ranging from 0.75% to 1.75% or the adjusted Eurodollar rate (as defined in the credit agreement) plus an applicable margin ranging from 1.75% to 2.75%, with the commitment fee ranging from 0.30% to 0.50% in each case based on our relative leverage at the time of determination. At December 31, 2018, the applicable margin under LIBOR borrowings was 2.50%, the interest rate was 5.03% and the unused portion of the Revolving Credit Facility totaled $784.0 million (subject to a commitment fee of 0.50%).

The Revolving Credit Facility is secured by the membership interests of Summit Holdings and the membership interests of all the subsidiaries of Summit Holdings and by substantially all of the assets of Summit Holdings and its subsidiaries (subject to exclusions set forth in the credit agreement). The credit agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability (i) to incur additional debt; (ii) to make investments; (iii) to engage in certain mergers, consolidations, acquisitions or sales of assets; (iv) to enter into swap agreements and power purchase agreements; (v) to enter into leases that would cumulatively obligate payments in excess of $50.0 million over any 12 -month period; and (vi) of Summit Holdings to make distributions, with certain exceptions, including the distribution of Available Cash (as defined in the SMLP Partnership Agreement) if no default or event of default then exists or would result therefrom and Summit Holdings is in pro forma compliance with its financial covenants. In addition, the Revolving Credit Facility requires Summit Holdings to maintain (i) a ratio of consolidated trailing 12 -month earnings before interest, income taxes, depreciation and amortization ("EBITDA") to net interest expense of not less than 2.5 to 1.0 as defined in the credit agreement, (ii) a ratio of total net indebtedness to consolidated trailing 12 -month EBITDA of not more than 5.50 to 1.00 and, (iii) a ratio of first lien net indebtedness to consolidated trailing 12 -month EBITDA of not more than 3.75 to 1.00.

As a result of the amendment, SMLP incurred approximately $8.1 million of debt issuance costs. As of December 31, 2018, we had $8.5 million of debt issuance costs attributable to our Revolving Credit Facility and related amendments which are included in noncurrent assets on the consolidated balance sheet.

As of December 31, 2018, we were in compliance with the Revolving Credit Facility's financial covenants. There were no defaults or events of default during the year ended December 31, 2018.

Senior Notes. In June 2013, Summit Holdings and its 100% owned finance subsidiary, Finance Corp. (together with Summit Holdings, the "Co-Issuers") co-issued $300.0 million of 7.5% senior unsecured notes (the "7.5% Senior Notes"). In July 2014, the Co-Issuers co-issued $300.0 million of 5.5% senior unsecured notes maturing August 15, 2022 (the "5.5% Senior Notes" and, together with the 5.75% Senior Notes (defined below, the “Senior Notes”).

On February 8, 2017, the Co-Issuers completed a public offering of $500.0 million of 5.75% senior unsecured notes (the "5.75% Senior Notes") as described below. Concurrent with the 5.75% Senior Notes offering, we made a tender offer to purchase all the outstanding 7.5% Senior Notes. The tender offer expired on February 14, 2017 and resulted in approximately $276.9 million of our 7.5% Senior Notes being validly tendered and retired. On February 16, 2017, we

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issued a notice of redemption for the remaining 7.5% Senior Notes. The remaining $23.1 million of 7.5% Senior Notes were redeemed on March 18, 2017 (the "redemption date"), with payment made on March 20, 2017. References to the “Senior Notes,” when used for dates or periods ended on or after the date of issuance of the 5.75% Senior Notes but before the redemption date, refer collectively to 5.5% Senior Notes, 7.5% Senior Notes and 5.75% Senior Notes. References to the "Senior Notes," when used for dates or periods ended on or prior to the date of issuance of the 5.75% Senior Notes, refer collectively to 5.5% Senior Notes and 7.5% Senior Notes. References to the "Senior Notes," when used for dates or periods that ended after the redemption date, refer collectively to the 5.5% Senior Notes and the 5.75% Senior Notes. In conjunction with the tender offer and mandatory redemption of the 7.5% Senior Notes, we paid redemption and call premiums totaling $17.9 million. These costs, as well as $4.1 million of unamortized debt issuance costs, are presented on our consolidated statement of operations as early extinguishment of debt.

In 2017, we executed supplemental indentures and amendments to our Revolving Credit Facility to add three newly formed entities, Summit Permian, Permian Finance and Summit Niobrara, as guarantors. In 2018, we executed supplemental indentures to include OpCo, Summit Utica, Meadowlark Midstream and Tioga Midstream as guarantors concurrent with the purchase of a 1% noncontrolling interest held by a subsidiary of Summit Investments (see Note 12 for additional details). As a result, Bison Midstream and its subsidiaries, Grand River and its subsidiary, DFW Midstream, Summit Marketing, Summit Permian, Permian Finance, Summit Niobrara, OpCo, Summit Utica, Meadowlark Midstream and Tioga Midstream (collectively the "Guarantor Subsidiaries") are 100% owned. The Guarantor Subsidiaries and SMLP fully and unconditionally and jointly and severally guarantee the 5.5% Senior Notes and the 5.75% Senior Notes. There are no significant restrictions on the ability of SMLP or Summit Holdings to obtain funds from its subsidiaries by dividend or loan. Finance Corp. has had no assets or operations since inception in 2013, we have no other independent assets or operations, and our non-guarantor subsidiaries are minor. At no time have the Senior Notes been guaranteed by the Co-Issuers.

5.75% Senior Notes. In February 2017, the Co-Issuers completed a public offering of $500.0 million of 5.75% senior unsecured notes maturing April 15, 2025. We pay interest on the 5.75% Senior Notes semi-annually in cash in arrears on April 15 and October 15 of each year. The 5.75% Senior Notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 5.75% Senior Notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. We used the proceeds from the issuance of the 5.75% Senior Notes to (i) fund the repurchase of the outstanding $300.0 million principal 7.5% Senior Notes, (ii) pay redemption and call premiums on the 7.5% Senior Notes totaling $17.9 million and (iii) pay $172.0 million of the balance outstanding under our Revolving Credit Facility.

At any time prior to April 15, 2020, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 5.75% Senior Notes at a redemption price of 105.750% of the principal amount of the 5.75% Senior Notes, plus accrued and unpaid interest, if any, but not including, the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after April 15, 2020, the Co-Issuers may redeem all or part of the 5.75% Senior Notes at a redemption price of 104.313% (with the redemption premium declining ratably each year to 100.000% on and after April 15, 2023), plus accrued and unpaid interest, if any, to, but not including, the redemption date. Debt issuance costs of $7.7 million are being amortized over the life of the 5.75% Senior Notes.

The 5.75% Senior Notes' indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 5.75% Senior Notes' indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 5.75% Senior Notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 5.75% Senior Notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days

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after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $75.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 5.75% Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 5.75% Senior Notes may declare all the 5.75% Senior Notes to be due and payable immediately.

5.5% Senior Notes. We pay interest on the 5.5% Senior Notes semi-annually in cash in arrears on February 15 and August 15 of each year. The 5.5% Senior Notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 5.5% Senior Notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. We used the proceeds from the issuance of the 5.5% Senior Notes to repay a portion of the balance outstanding under our Revolving Credit Facility.

At any time prior to August 15, 2018, the Co-Issuers may redeem all or part of the 5.5% Senior Notes at a redemption price of 104.125% (with the redemption premium declining ratably each year to 100.000% on and after August 15, 2020), plus accrued and unpaid interest, if any. Debt issuance costs of $5.1 million are being amortized over the life of the 5.5% Senior Notes.

The 5.5% Senior Notes' indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 5.5% Senior Notes' indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 5.5% Senior Notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 5.5% Senior Notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 5.5% Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 5.5% Senior Notes may declare all the 5.5% Senior Notes to be due and payable immediately.

As of and during the December 31, 2018, we were in compliance with the financial covenants governing our Senior Notes. There were no defaults or events of default during the year ended December 31, 2018.

11. FINANCIAL INSTRUMENTS

Concentrations of Credit Risk. Financial instruments that potentially subject us to concentrations of credit risk consist of cash and cash equivalents and accounts receivable. We maintain our cash and cash equivalents in bank deposit accounts that frequently exceed federally insured limits. We have not experienced any losses in such accounts and do not believe we are exposed to any significant risk.

Accounts receivable primarily comprise amounts due for the gathering, treating and processing services we provide to our customers and also the sale of natural gas liquids resulting from our processing services. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of our counterparties and can require letters of credit for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated. Our top five customers or counterparties accounted for 39% of total accounts receivable at December 31, 2018, compared with 44% as of December 31, 2017.

Fair Value. The carrying amount of cash and cash equivalents, accounts receivable and trade accounts payable reported on the balance sheet approximates fair value due to their short-term maturities.

The Deferred Purchase Price Obligation's carrying value is its fair value because carrying value represents the present value of the payment expected to be made in 2020. Our calculation of the Deferred Purchase Price Obligation involves significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a material effect on the ultimate cash payment and the Deferred Purchase Price Obligation. As such, its fair value measurement is classified as a non-recurring Level 3 measurement in the fair value hierarchy because our assumptions and judgments are not observable from objective sources (see Notes 17 and 19).

The Deferred Purchase Price Obligation represents our only Level 3 financial instrument fair value measurement. A rollforward of our Level 3 liability measured at fair value on a recurring basis follows (in thousands).

| | |
|---|---|
| Level 3 liability, January 1, 2017 | $563,281 |
| Change in fair value | (200,322 ) |
| Level 3 liability, December 31, 2017 | 362,959 |
| Change in fair value | 20,975 |
| Level 3 liability, December 31, 2018 | $383,934 |

A summary of the estimated fair value of our debt financial instruments follows.

| | December 31, 2018 | | December 31, 2017 | |
|---|---|---|---|---|
| | Carrying value | Estimated fair value (Level 2) | Carrying value | Estimated fair value (Level 2) |

| | (In thousands) | | | |
|---|---|---|---|---|
| Summit Holdings 5.5% Senior Notes ($300.0 million principal) | $297,638 | $286,625 | $297,090 | $301,750 |
| Summit Holdings 5.75% Senior Notes ($500.0 million principal) | 494,093 | 455,208 | 493,102 | 501,667 |

The carrying value on the balance sheet of the Revolving Credit Facility is its fair value due to its floating interest rate. The fair value for the Senior Notes is based on an average of nonbinding broker quotes as of December 31, 2018 and 2017. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the Senior Notes.

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12. PARTNERS' CAPITAL

A rollforward of the number of common limited partner, preferred limited partner and General Partner units follows.

| | Limited partners | | | General |
|---|---|---|---|---|
| | Series A Preferred Units | Common | Subordinated | Partner |
| Units, January 1, 2016 | — | 42,062,644 | 24,409,850 | 1,354,700 |
| Subordinated units conversion | — | 24,409,850 | (24,409,850 ) | — |
| Units issued in connection with the September 2016 Equity Offering | — | 5,500,000 | — | — |
| General Partner 2% contribution | — | — | — | 112,245 |
| Net units issued under the SMLP LTIP | — | 138,627 | — | 4,242 |
| Units, December 31, 2016 | — | 72,111,121 | — | 1,471,187 |
| Units issued in connection with the November 2017 Equity Offering | 300,000 | — | — | — |
| Net units issued under the SMLP LTIP | — | 211,327 | — | — |
| Units issued under ATM program | — | 763,548 | — | — |
| General Partner 2% contribution | — | — | — | 19,812 |
| Units, December 31, 2017 | 300,000 | 73,085,996 | — | 1,490,999 |
| Net units issued under the SMLP LTIP | — | 304,857 | — | — |
| Units, December 31, 2018 | 300,000 | 73,390,853 | — | 1,490,999 |

Unit Offerings. In September 2016, we completed an underwritten public offering of 5,500,000 common units at a price of $23.20 per unit pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC (the "September 2016 Equity Offering"). Following the September 2016 Equity Offering, our General Partner made a capital contribution to us to maintain its approximate 2% general partner interest. We used the net proceeds from the September 2016 Equity Offering to pay down our Revolving Credit Facility.

In February 2017, we completed a secondary underwritten public offering of 4,000,000 SMLP common units held by a subsidiary of Summit Investments pursuant to the 2016 SRS. We did not receive any proceeds from this offering.

Subordination. The subordination period ended in conjunction with the February 2016 distribution payment in respect of the fourth quarter of 2015 and the then-outstanding subordinated units converted to common units on a one-for-one basis. Prior to the end of the subordination period, the principal difference between our common units and subordinated units was that holders of the subordinated units were not entitled to receive any distribution of available cash until the common units had received the minimum quarterly distribution ("MQD") plus any arrearages in the payment of the MQD from prior quarters.

At-the-market Program. In February 2017, we executed a new equity distribution agreement and filed a prospectus with the SEC for the issuance and sale from time to time of SMLP common units having an aggregate offering price of up to $150.0 million (the "ATM Program"). These sales will be made (i) pursuant to the terms of the equity distribution agreement between us and the sales agents named therein and (ii) by means of ordinary brokers' transactions at market prices, in block transactions or as otherwise agreed between us and the sales agents. Sales of our common units may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined by SEC rules.

During the year ended December 31, 2018, there were no transactions under the ATM Program. During the year ended December 31, 2017, we sold 763,548 units under the ATM Program for aggregate gross proceeds of $17.7 million, and paid approximately $0.2 million as compensation to the sales agents pursuant to the terms of the equity distribution agreement. After taking into account the aggregate sales price of common units sold under the ATM Program through December 31, 2018, we have the capacity to issue additional common units under the ATM Program up to an aggregate $132.3 million.

Series A Preferred Units. In November 2017, we issued 300,000 Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Series A Preferred Units”) representing limited partner interests in the

Partnership at a price to the public of $1,000 per unit. We used the net proceeds of $293.2 million (after deducting underwriting discounts and offering expenses) to repay outstanding borrowings under our revolving credit facility.

The Series A Preferred Units rank senior to (i) common units and incentive distribution rights, each representing limited partner interests in the Partnership and (ii) each other class or series of limited partner interests or other equity securities in the Partnership that may be established in the future that expressly ranks junior to the Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event (the "Junior Securities"). The Series A Preferred Units rank equal in all respects with each class or series of limited partner interests or other equity securities in the Partnership that may be established in the future that is not expressly made senior or subordinated to the Series A Preferred Units as to the payment of distributions and amounts payable on a liquidation event (the "Parity Securities"). The Series A Preferred Units rank junior to (i) all of the Partnership's existing and future indebtedness and other liabilities with respect to assets available to satisfy claims against the Partnership and (ii) each other class or series of limited partner interests or other equity securities in the Partnership established in the future that is expressly made senior to the Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event. Income is allocated to the Series A Preferred Units in an amount equal to the earned distributions for the respective reporting period.

Distributions on the Series A Preferred Units are cumulative and compounding and are payable semi-annually in arrears on the 15th day of each June and December through and including December 15, 2022, and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year (each, a "Distribution Payment Date") to holders of record as of the close of business on the first business day of the month of the applicable Distribution Payment Date, in each case, when, as, and if declared by the General Partner out of legally available funds for such purpose.

The initial distribution rate for the Series A Preferred Units is 9.50% per annum of the $1,000 liquidation preference per Series A Preferred Unit. On and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of the liquidation preference equal to the three-month LIBOR plus a spread of 7.43%.

Noncontrolling Interest. At December 31, 2017, we recorded Summit Investments' indirect retained ownership interest in OpCo and its subsidiaries as a noncontrolling interest in the consolidated financial statements.

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of the 2016 Drop Down Assets that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for the 2016 Drop Down Assets for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. Net income or loss was attributed to Summit Investments for the 2016 Drop Down Assets for the period from January 1, 2016 to March 3, 2016.

Although included in partners' capital, any net income or loss attributable to Summit Investments is excluded from the calculation of EPU.

2016 Drop Down. On March 3, 2016, we acquired the 2016 Drop Down Assets from a subsidiary of Summit Investments. We paid cash consideration of $360.0 million and recognized a Deferred Purchase Price Obligation of

$507.4 million in exchange for Summit Investments' $1.11 billion net investment in the 2016 Drop Down Assets (see Note 17). In June 2016, we received a working capital adjustment of $0.6 million from a subsidiary of Summit Investments. We recognized a capital contribution from Summit Investments for the difference between (i) the net cash consideration paid and the Deferred Purchase Price Obligation and (ii) Summit Investments' net investment in the 2016 Drop Down Assets.

Cash Distribution Policy

Our Partnership Agreement requires that we distribute all of our available cash (as defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date. The amount of distributions paid under

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our policy is subject to fluctuations based on the amount of cash we generate from our business and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement.

General Partner Interest. Our General Partner is entitled to an equivalent percentage of all distributions that we make prior to our liquidation based on its respective general partner interest, up to a maximum of 2%. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our General Partner's interest in our distributions will be reduced if we issue additional units in the future and our General Partner does not contribute a proportionate amount of capital to us to maintain its general partner interest immediately prior to the unit issuance. If the recently announced Equity Restructuring is consummated, the 2% general partner interest will be converted into a non-economic general partner interest.

Cash Distributions Paid and Declared. We paid the following per-unit distributions during the years ended December 31:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Per-unit distributions to unitholders | $2.300 | $2.300 | $2.300 |

On January 24, 2019, the Board of Directors of our General Partner declared a distribution of $0.575 per unit for the quarterly period ended December 31, 2018. This distribution, which totaled $45.3 million, was paid on February 14, 2019 to unitholders of record at the close of business on February 7, 2019. As announced on February 26, 2019, beginning with the quarter ending March 31, 2019, we expect to reduce our distribution on the common units to $0.2875.

We allocated the February 2019 distribution in accordance with the third target distribution level (see "Incentive Distribution Rights—Percentage Allocations of Available Cash" below for additional information.)

Incentive Distribution Rights.

Our General Partner also currently holds IDRs that entitle it to receive increasing percentage allocations of the cash we distribute from operating surplus (as set forth in the chart below). The maximum distribution includes distributions paid to our General Partner on an assumed 2% general partner interest. The maximum distribution does not include any distributions that our General Partner may receive on any common units that it owns.

Percentage Allocations of Available Cash. The following table illustrates the percentage allocations of available cash between the unitholders and our General Partner based on the specified target distribution levels. The amounts set forth in the column Marginal Percentage Interest in Distributions are the percentage interests of our General Partner and the unitholders in any available cash we distribute up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit Target Amount. The percentage interests shown for our unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the MQD. The percentage interests set forth below for our General Partner assume (i) a 2% general partner interest, (ii) that our General Partner has not transferred its IDRs and (iii) that there are no arrearages on common units.

| | Total quarterly distribution per unit target amount | Marginal percentage interest in distributions Unitholders | General Partner |
|---|---|---|---|
| Minimum quarterly distribution | $0.40 | 98% | 2% |
| First target distribution | $0.40 up to $0.46 | 98% | 2% |
| Second target distribution | above $0.46 up to $0.50 | 85% | 15% |
| Third target distribution | above $0.50 up to $0.60 | 75% | 25% |
| Thereafter | above $0.60 | 50% | 50% |

Our distributions in 2016, 2017 and 2018 have all been within the Third target distribution level.

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Our payment of IDRs as reported in distributions to unitholders – General Partner in the statements of partners' capital during the years ended December 31 follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| IDR payments | $8,535 | $8,460 | $7,912 |

For the purposes of calculating net income attributable to General Partner in the statements of operations and partners' capital, the financial impact of IDRs is recognized in respect of the quarter for which the distributions were declared. For the purposes of calculating distributions to unitholders in the statements of partners' capital and cash flows, IDR payments are recognized in the quarter in which they are paid.

## 13. EARNINGS PER UNIT

The following table details the components of EPU.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands, except per-unit amounts) | | |
| Numerator for basic and diluted EPU: | | | |
| Allocation of net income (loss) among limited partner interests: | | | |
| Net income (loss) attributable to limited partners | $32,799 | $75,485 | $(48,179) |
| Less net income attributable to Series A Preferred Units | 28,500 | 3,563 | — |
| Net income (loss) attributable to common limited partners | $4,299 | $71,922 | $(48,179) |
| | | | |
| Denominator for basic and diluted EPU: | | | |
| Weighted-average common units outstanding – basic | 73,304 | 72,705 | 68,264 |
| Effect of nonvested phantom units | 311 | 342 | — |
| Weighted-average common units outstanding – diluted | 73,615 | 73,047 | 68,264 |
| | | | |
| Earnings (loss) per limited partner unit: | | | |
| Common unit – basic | $0.06 | $0.99 | $(0.71) |
| Common unit – diluted | $0.06 | $0.98 | $(0.71) |
| | | | |
| Nonvested anti-dilutive phantom units excluded from the calculation of diluted EPU | 2 | 42 | 125 |

14. UNIT-BASED AND NONCASH COMPENSATION

SMLP Long-Term Incentive Plan. The SMLP LTIP provides for equity awards to eligible officers, employees, consultants and directors of our General Partner and its affiliates, thereby linking the recipients' compensation directly to SMLP’s performance. The SMLP LTIP is administered by our General Partner's Board of Directors, though such administration function may be delegated to a committee appointed by the board. A total of 5.0 million common units was reserved for issuance pursuant to and in accordance with the SMLP LTIP. As of December 31, 2018, approximately 3.2 million common units remained available for future issuance.

The SMLP LTIP provides for the granting, from time to time, of unit-based awards, including common units, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Grants are made at the discretion of the Board of Directors or Compensation Committee of our General Partner. The administrator of the SMLP LTIP may make grants under the SMLP LTIP that contain such terms, consistent with the SMLP LTIP, as the administrator may determine are appropriate, including vesting conditions. The administrator of the SMLP LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the SMLP LTIP) or as otherwise described in an award agreement. Termination of employment prior to

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vesting will result in forfeiture of the awards, except in limited circumstances as described in the plan documents. Units that are canceled or forfeited will be available for delivery pursuant to other awards.

The following table presents phantom unit activity:

| | Units | Weighted-average grant date fair value |
|---|---|---|
| Nonvested phantom units, January 1, 2016 | 379,911 | $ 31.13 |
| Phantom units granted | 495,535 | 14.91 |
| Phantom units vested | (178,953 ) | 33.80 |
| Phantom units forfeited | (4,538 ) | 16.89 |
| Nonvested phantom units, December 31, 2016 | 691,955 | 19.59 |
| Phantom units granted | 371,972 | 22.50 |
| Phantom units vested | (293,222 ) | 24.76 |
| Phantom units forfeited | (21,431 ) | 20.07 |
| Nonvested phantom units, December 31, 2017 | 749,274 | 20.07 |
| Phantom units granted | 515,358 | 15.25 |
| Phantom units vested | (359,016 ) | 22.39 |
| Phantom units forfeited | (41,492 ) | 17.27 |
| Nonvested phantom units, December 31, 2018 | 864,124 | $ 17.11 |

A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. Distribution equivalent rights for each phantom unit provide for a lump sum cash amount equal to the accrued distributions from the grant date to be paid in cash upon the vesting date.

Phantom units granted to date vest ratably over a three-year period. Grant date fair value is determined based on the closing price of our common units on the date of grant multiplied by the number of phantom units awarded to the grantee. Forfeitures are recorded as incurred. Holders of all phantom units granted to date are entitled to receive distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. Upon vesting, phantom unit awards may be settled, at our discretion, in cash and/or common units, but the current intention is to settle all phantom unit awards with common units.

The intrinsic value of phantom units that vested during the years ended December 31, follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Intrinsic value of vested LTIP awards | $5,393 | $6,657 | $2,957 |

As of December 31, 2018, the unrecognized unit-based compensation related to the SMLP LTIP was $4.9 million. Incremental unit-based compensation will be recorded over the remaining vesting period of approximately 2.2 years.

Unit-based compensation recognized in general and administrative expense related to awards under the SMLP LTIP follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| SMLP LTIP unit-based compensation | $8,328 | $7,951 | $7,550 |

15. RELATED-PARTY TRANSACTIONS

Acquisitions. See Notes 1, 12 and 17 for disclosure of the 2016 Drop Down and the funding of transactions.

Reimbursement of Expenses from General Partner. Our General Partner and its affiliates do not receive a management fee or other compensation in connection with the management of our business, but will be reimbursed for expenses incurred on our behalf. Under our Partnership Agreement, we reimburse our General Partner and its

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affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our General Partner's employees and executive officers who perform services necessary to run our business. Our Partnership Agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The "Due to affiliate" line item on the consolidated balance sheet represents the payables to our General Partner for expenses incurred by it and paid on our behalf.

Expenses incurred by the General Partner and reimbursed by us under our Partnership Agreement were as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Operation and maintenance expense | $29,061 | $27,450 | $26,485 |
| General and administrative expense | 30,119 | 30,899 | 31,947 |

In February 2017, SMP Holdings sold 4,000,000 common units representing limited partner interests in SMLP at a price to the public of $24.00 per common unit. Consistent with our obligations under the Partnership Agreement, we paid all costs and expenses of the secondary offering (other than underwriting discounts and fees and expenses of counsel and advisors to SMP Holdings in the sale). We did not receive any of the proceeds from the secondary offering.

## 16. COMMITMENTS AND CONTINGENCIES

Operating Leases. We and Summit Investments lease certain office space and equipment to support our operations. We have determined that our leases are operating leases. We recognize total rent expense incurred or allocated to us in general and administrative expenses. Rent expense related to operating leases, including rent expense incurred on our behalf and allocated to us, was as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (In thousands) | | |
| Rent expense | $3,928 | $3,772 | $2,861 |

We lease office space and equipment under agreements that expire in various years through 2028. Future minimum lease payments due under noncancelable operating leases at December 31, 2018, were as follows (in thousands):

| | |
|---|---|
| 2019 | $3,133 |
| 2020 | 1,018 |
| 2021 | 550 |

| | |
|---|---|
| 2022 | 506 |
| 2023 | 373 |
| Thereafter | 621 |
| Total future minimum lease payments | $6,201 |

Environmental Matters. Although we believe that we are in material compliance with applicable environmental regulations, the risk of environmental remediation costs and liabilities are inherent in pipeline ownership and operation. Furthermore, we can provide no assurances that significant environmental remediation costs and liabilities will not be incurred by the Partnership in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters, except as noted below.

In 2015, Summit Investments learned of the rupture of a four-inch produced water gathering pipeline on the Meadowlark Midstream system near Williston, North Dakota. The incident, which was covered by Summit Investments' insurance policies, was subject to maximum coverage of $25.0 million from its pollution liability insurance policy and $200.0 million from its property and business interruption insurance policy. Summit Investments exhausted the $25.0 million pollution liability policy in 2015. We submitted property and business interruption claim requests to the insurers and reached a settlement in January 2017. In connection therewith, we recognized $2.6 million of business interruption recoveries and $0.4 million of property recoveries.

A rollforward of the aggregate accrued environmental remediation liabilities follows.

| | Total (In thousands) |
|---|---|
| Accrued environmental remediation, January 1, 2017 | $ 9,453 |
| Payments made | (4,109) |
| Accrued environmental remediation, December 31, 2017 | $ 5,344 |
| Payments made | (3,808) |
| Additional accruals | 4,100 |
| Accrued environmental remediation, December 31, 2018 | $ 5,636 |

During 2018, we established additional environmental remediation accruals. As of December 31, 2018, we have recognized (i) a current liability for expenditures expected to be incurred within the next 12 months and (ii) a noncurrent liability for estimated expenditures expected to be incurred subsequent to December 31, 2019. Each of these amounts represent our best estimate for costs expected to be incurred. Neither of these amounts has been discounted to its present value.

While we cannot predict the ultimate outcome of this matter with certainty for Summit Investments or Meadowlark Midstream, especially as it relates to any material liability as a result of any governmental proceeding related to the incident, we believe at this time that it is unlikely that SMLP or its General Partner will be subject to any material liability as a result of any governmental proceeding related to the rupture.

Legal Proceedings. The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims or those arising in the normal course of business would not individually or in the aggregate have a material adverse effect on the Partnership's financial position or results of operations.

## 17. ACQUISITIONS AND DROP DOWN TRANSACTIONS

2016 Drop Down. On March 3, 2016, SMLP acquired a controlling interest in OpCo, the entity which owns the 2016 Drop Down Assets. These assets include certain natural gas, crude oil and produced water gathering systems located in the Utica Shale, the Williston Basin and the DJ Basin as well as ownership interests in a natural gas gathering system and a condensate stabilization facility, both located in the Utica Shale.

The net consideration paid and recognized in connection with the 2016 Drop Down (i) consisted of a cash payment to SMP Holdings of $360.0 million funded with borrowings under our Revolving Credit Facility and a $0.6 million working capital adjustment received in June 2016 (the “Initial Payment”) and (ii) includes the Deferred Purchase Price Obligation payment due in 2020.

The Deferred Purchase Price Obligation will be equal to:

- six-and-one-half (6.5) multiplied by the average Business Adjusted EBITDA, as defined below and in the Contribution Agreement, of the 2016 Drop Down Assets for 2018 and 2019, less the G&A Adjuster, as

defined in the Contribution Agreement;
- less the Initial Payment;
- less all capital expenditures incurred for the 2016 Drop Down Assets between the March 3, 2016 and December 31, 2019;
- plus all Business Adjusted EBITDA from the 2016 Drop Down Assets between March 3, 2016 and December 31, 2019, less the Cumulative G&A Adjuster, as defined in the Contribution Agreement.

Business Adjusted EBITDA is defined as the net income or loss of the 2016 Drop Down Assets for such period:

- plus interest expense, income tax expense and depreciation and amortization of the 2016 Drop Down Assets for such period;

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- plus any adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses with respect to the 2016 Drop Down Assets for such period;
- plus any Special Liability Expenses, as defined below and in the Contribution Agreement, for such period;
- less interest income and income tax benefit of the 2016 Drop Down Assets for such period;
- less adjustments related to any other noncash income or gains with respect to the 2016 Drop Down Assets for such period.

Business Adjusted EBITDA shall exclude the effect of any Partnership expenses allocated by or to SMLP or its affiliates in respect of the 2016 Drop Down Assets, such as general and administrative expenses (including compensation-related expenses and professional services fees), transaction costs, allocated interest expense and allocated income tax expense.

Special Liability Expenses are defined as any and all expenses incurred by SMLP with respect to the Special Liabilities, as defined in the Contribution Agreement, including fines, legal fees, consulting fees and remediation costs.

The present value of the Deferred Purchase Price Obligation will be reflected as a liability on our balance sheet until paid. As of the acquisition date, the estimated future payment obligation (based on management's estimate of the Partnership's share of forecasted Business Adjusted EBITDA and capital expenditures for the 2016 Drop Down Assets) was estimated to be $860.3 million and had a net present value of $507.4 million, using a discount rate of 13.0%. As of December 31, 2018, Remaining Consideration was estimated to be $423.9 million and the net present value, as recognized on the consolidated balance sheet, was $383.9 million, using a discount rate of 8.25%. Any subsequent changes to the estimated future payment obligation will be calculated using a discounted cash flow model with a commensurate risk-adjusted discount rate. Such changes and the impact on the liability due to the passage of time will be recorded as a change in the Deferred Purchase Price Obligation fair value on the consolidated statements of operations in the period of the change. See Note 19 for additional information.

At the discretion of the Board of Directors of our General Partner, the Deferred Purchase Price Obligation can be paid in cash, SMLP common units or a combination thereof. We currently expect that the Deferred Purchase Price Obligation will be financed with a combination of (i) borrowings under our Revolving Credit Facility, (ii) the net proceeds from the issuance of senior unsecured debt by us, (iii) net proceeds from the issuance of equity securities by us and/or (iv) other internally generated sources of cash.

Ohio Gathering. For information on the acquisition and initial recognition of Ohio Gathering, see Note 8.

Supplemental Disclosures – As-If Pooled Basis. As a result of accounting for our drop down transactions similar to a pooling of interests, our historical financial statements and those of the acquired drop down assets have been combined to reflect the historical operations, financial position and cash flows of the acquired drop down assets from the date common control began. Revenues and net income for the previously separate entities and the combined amounts, as presented in these consolidated financial statements follow.

| | Year ended December 31, 2016 (In thousands) |
|---|---|

| | |
|---|---|
| SMLP revenues | $ 393,495 |
| 2016 Drop Down Assets revenues (1) | 8,867 |
| Combined revenues | $ 402,362 |
| | |
| SMLP net loss | $ (40,932 ) |
| 2016 Drop Down Assets net income (1) | 2,745 |
| Combined net loss | $ (38,187 ) |

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(1) Results are fully reflected in SMLP's results of operations subsequent to closing the respective drop down.

## 18. UNAUDITED QUARTERLY FINANCIAL DATA

Summarized information on the consolidated results of operations for each of the quarters during the two-year period ended December 31, 2018, follows.

| | Quarter ended | | | |
|---|---|---|---|---|
| | December 31, 2018 | September 30, 2018 | June 30, 2018 | March 31, 2018 |
| | (In thousands, except per-unit amounts) | | | |
| Total revenues | $133,671 | $127,479 | $128,183 | $117,320 |
| Net income (loss) attributable to SMLP | $38,654 | $57,430 | $(49,971) | $(3,930) |
| Less net income and IDRs attributable to General Partner | 2,907 | 3,279 | 1,140 | 2,058 |
| Less net income attributable to Series A Preferred Units | 7,125 | 7,125 | 7,125 | 7,125 |
| Net income (loss) attributable to common limited partners | $28,622 | $47,026 | $(58,236) | $(13,113) |
| Earnings (loss) per limited partner unit: | | | | |
| Common unit - basic | $0.39 | $0.64 | $(0.79) | $(0.18) |
| Common unit - diluted | $0.39 | $0.64 | $(0.79) | $(0.18) |

| | Quarter ended | | | |
|---|---|---|---|---|
| | December 31, 2017 | September 30, 2017 | June 30, 2017 | March 31, 2017 |
| | (In thousands, except per-unit amounts) | | | |
| Total revenues | $126,199 | $124,945 | $101,792 | $135,805 |
| Net (loss) income attributable to SMLP | $(18,331) | $93,546 | $11,157 | $(685) |
| Less net income and IDRs attributable to General Partner | 1,760 | 3,999 | 2,351 | 2,092 |
| Less net income attributable to Series A Preferred Units | 3,563 | — | — | — |
| Net (loss) income attributable to common limited partners | $(23,654) | $89,547 | $8,806 | $(2,777) |
| (Loss) earnings per limited partner unit: | | | | |
| Common unit - basic | $(0.32) | $1.23 | $0.12 | $(0.04) |
| Common unit - diluted | $(0.32) | $1.22 | $0.12 | $(0.04) |

## 19. SUBSEQUENT EVENTS

We have evaluated subsequent events for recognition or disclosure in the consolidated financial statements and no events have occurred that require adjustment to or disclosure in the consolidated financial statements, except for the following:

On February 26, 2019, SMLP announced that it had executed definitive agreements (the “Tioga PSAs”) with Hess Infrastructure related to the sale of Tioga Midstream for cash consideration of $90 million, subject to adjustment. The transaction is subject to customary closing conditions and is expected to close before the end of the first quarter of 2019. SMLP intends to use the net proceeds from the sale to repay outstanding indebtedness under its revolving credit facility.

Also, on February 26, 2019, SMLP announced that it signed an amendment to the Contribution Agreement (the “Amendment”) related to the 2016 Drop Down pursuant to which the Partnership shall, as soon as reasonably practicable following the closing of the transactions under the Tioga PSAs, make a cash payment of $100 million to SMP Holdings. Following the closing of the Amendment, the Remaining Consideration will be fixed at $303.5 million, and will be payable by the Partnership in one or more payments over the period from March 1, 2020 through

December 31, 2020, payable in (i) cash, (ii) the Partnership's common units or (iii) a combination of cash and the Partnership's common units, at the discretion of the Partnership. No less than50% of the Remaining Consideration shall be paid on or before June 30, 2020 and interest shall accrue at a rate of 8% per annum on any portion of the Remaining Consideration that remains unpaid after March 31, 2020.

In addition, SMLP signed an equity restructuring agreement with the General Partner and SMP Holdings (the "Equity Restructuring Agreement") pursuant to which the IDRs and the 2% general partner interest held by the General Partner will be converted into 8,750,000 common units and a non-economic general partner interest (the "Equity Restructuring" and collectively with the Tioga PSAs and the Amendment, the "February 2019 Transactions").

The February 2019 Transactions are expected to close before the end of the first quarter of 2019, subject to customary closing conditions. Immediately following the closing of the Equity Restructuring Agreement, SMP Holdings will directly own a 42.1% limited partner interest in SMLP and an affiliate of Energy Capital Partners II, LLC will directly own a 7.2% limited partner interest in SMLP. In connection with the February 2019 Transactions, the Partnership announced that it expects to reduce its common unit distribution to $0.2875 per quarter, beginning with the distribution to be paid in respect of the first quarter of 2019.

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

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure matters during the years ended December 31, 2018 and 2017.

## Item 9A. Controls and Procedures.

### Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to the management of our General Partner, including our General Partner's principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. SMLP's management, with the participation of the Chief Executive Officer and Chief Financial Officer of SMLP's General Partner, has evaluated the effectiveness of SMLP's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report (the "Evaluation Date"). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of SMLP's General Partner have concluded that, as of the Evaluation Date, SMLP's disclosure controls and procedures are effective.

### Changes in Internal Control Over Financial Reporting

There have not been any changes in SMLP's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of 2018 that have materially affected, or are reasonably likely to materially affect, SMLP's internal control over financial reporting.

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Management’s Annual Report on Internal Control Over Financial Reporting

Our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting for the Partnership. With our participation, an evaluation of the effectiveness of our internal control over financial reporting was conducted as of December 31, 2018, based on the framework and criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2018. Our independent registered public accounting firm has issued an audit report on our internal control over financial reporting, included below of this report.

/s/ Leonard W. Mallett
Leonard W. Mallett
President and Chief Executive Officer, Summit Midstream GP, LLC (the General Partner of SMLP)

/s/ Marc D. Stratton
Marc D. Stratton
Executive Vice President and Chief Financial Officer, Summit Midstream GP, LLC (the General Partner of SMLP)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Summit Midstream, GP, LLC and the unitholders of Summit Midstream Partners, LP
The Woodlands, Texas

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2018, of the Partnership and our report dated February 26, 2019 expressed an unqualified opinion on those financial statements based on our audit and the report of other auditors.

Basis for Opinion

The Partnership’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 Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership'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 Partnership 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

An entity’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. An entity’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 entity; (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 entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity’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/ Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2019

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Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Management of Summit Midstream Partners, LP

We are managed by the directors and executive officers of our General Partner, Summit Midstream GP, LLC. Our General Partner is not elected by our unitholders and will not be subject to re-election in the future. Summit Investments, which is controlled by Energy Capital Partners, owns and controls SMP Holdings, the sole owner of our General Partner. SMP Holdings has the right to appoint the entire Board of Directors of our General Partner, including our independent directors. All decisions of the Board of Directors of our General Partner will require the affirmative vote of a majority of all of the directors constituting the board, provided that such majority includes at least a majority of the directors designated as an "Energy Capital Partner Designated Director" by Energy Capital Partners. The Energy Capital Partner Designated Directors are Matthew F. Delaney, Peter Labbat, Thomas K. Lane, Scott A. Rogan and Jeffrey R. Spinner. Our unitholders are not entitled to directly or indirectly participate in our management or operations. Our General Partner is liable, as General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness (including the outstanding indebtedness under our Revolving Credit Facility) or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our General Partner.

Our General Partner's limited liability company agreement provides that the Board of Directors of our General Partner must obtain the approval of members representing a majority interest in our General Partner for certain actions affecting us. These include actions related to:

- transactions with affiliates;
- entering into any hedging transactions that are not in compliance with GAAP;
- the voluntary liquidation, wind-up or dissolution of us or any of our subsidiaries;
- making any election that would result in us being classified as other than a partnership or a disregarded entity for U.S. federal income tax purposes;
- filing or consenting to the filing of any bankruptcy, insolvency or reorganization petition for relief from debtors or protection from creditors naming us or any of our subsidiaries; and
- effecting a material amendment to our General Partner's limited liability company agreement.

Currently, SMP Holdings is the sole member of our General Partner.

Committees of the Board of Directors

The Board of Directors of our General Partner has an Audit Committee, a Conflicts Committee and a Compensation Committee and may have such other committees as the Board of Directors shall determine from time to time.

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The table below shows the current membership of each standing board committee and indicates which directors are independent directors.

| Name | Audit Committee | Conflicts Committee | Compensation Committee | Independent Director |
|---|---|---|---|---|
| Matthew F. Delaney | | | | No |
| Peter Labbat | | | | No |
| Thomas K. Lane | | | Chair | No |
| Leonard W. Mallett | | | | No |
| Jerry L. Peters | Chair | Member | | Yes |
| Scott A. Rogan | | | | No |
| Jeffrey R. Spinner | | | Member | No |
| Robert M. Wohleber | Member | Chair | Member | Yes |

Each of the standing committees of the Board of Directors will have the composition and responsibilities described below.

Audit Committee. Jerry L. Peters and Robert M. Wohleber serve as the members of the Audit Committee. Mr. Peters serves as the chair of our Audit Committee. In this role, Mr. Peters satisfies the SEC and New York Stock Exchange rules regarding independence and qualifies as an Audit Committee financial expert.

The Audit Committee assists the Board of Directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The Audit Committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has unrestricted access to the Audit Committee.

Our Audit Committee has adopted an audit committee charter, which is publicly available on our website under the "Corporate Governance" subsection of the “Investors” section at *www.summitmidstream.com*.

As disclosed in Item 5.02 of the Current Report on Form 8-K filed by us with the United States Securities and Exchange Commission on September 19, 2018, Susan Tomasky resigned from her memberships on the Board of Directors and all of its committees effective October 1, 2018. As a result of Ms. Tomasky’s resignation, we are temporarily deficient of the requirement under Section 303A.07(a) of the NYSE Listed Company Manual that audit committees be comprised of at least three independent directors. We have undertaken a search for a new independent director and expect to announce a replacement for Ms. Tomasky, and regain compliance with the applicable NYSE listing standard, in a timely manner.

Conflicts Committee. At the direction of our General Partner, our Conflicts Committee will review specific matters that may involve conflicts of interest in accordance with the terms of our Partnership Agreement. The Conflicts Committee will determine the resolution of the conflict of interest that is in the best interests of the Partnership. There is no requirement that our General Partner seek the approval of the Conflicts Committee for the resolution of any conflict. The members of the Conflicts Committee may not be officers or employees of our General Partner or directors, officers, or employees of any of its affiliates. They may not hold any ownership interest in our General Partner or us and our subsidiaries other than common units and other awards that are granted under our incentive plans in place from time to time. Furthermore, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. Mr. Peters and Mr. Wohleber currently serve as the members of our Conflicts Committee, with Mr. Wohleber serving as chair of the committee.

Any matters approved by the Conflicts Committee in good faith will be conclusively deemed to be approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the Conflicts Committee will have the burden of proving that the members of the Conflicts Committee did not subjectively believe that the matter was in the best interests of the Partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our General Partner (or any members of the Board of Directors of our General Partner including any member of the Conflicts Committee) reasonably believes the advice or opinion to be within such person's professional or expert competence, shall be conclusively presumed to have been taken or omitted in good faith.

Compensation Committee. Mr. Lane, Mr. Spinner and Mr. Wohleber serve as the members of the Compensation Committee, with Mr. Lane serving as chair of the committee. The Compensation Committee provides oversight, administers and makes decisions regarding our executive compensation policies and incentive plans. Although our common units are listed on the NYSE, we qualify for the "Limited Partnership" exemption to the NYSE rule that would otherwise require listed companies to have an independent compensation committee with a written charter.

Directors and Executive Officers

Directors of our General Partner are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the Board of Directors of our General Partner.

The following table shows information for the directors and executive officers of our General Partner as of February 25, 2019.

| Name | Age | Position with Summit Midstream GP, LLC |
|---|---|---|
| Leonard W. Mallett (1) | 62 | President, Chief Executive Officer and Director, Chief Operations Officer |
| Marc D. Stratton | 41 | Executive Vice President and Chief Financial Officer |
| Brock M. Degeyter | 42 | Executive Vice President, General Counsel, Chief Compliance Officer and Secretary |
| Brad N. Graves | 52 | Executive Vice President and Chief Commercial Officer |
| Louise E. Matthews | 49 | Executive Vice President, Chief Administration Officer |
| Matthew F. Delaney | 32 | Director |
| Peter Labbat | 53 | Director |
| Thomas K. Lane | 62 | Director |
| Jerry L. Peters | 61 | Director |
| Scott A. Rogan | 48 | Director |
| Jeffrey R. Spinner | 37 | Director |
| Robert M. Wohleber | 68 | Director |

(1) On February 21, 2019, Steven J. Newby resigned from his positions as President, Chief Executive Officer and Director of our General Partner. Concurrently with Mr. Newby's resignation, Mr. Mallett was appointed President and Chief Executive Officer, as well as a director of our General Partner, on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

Leonard W. Mallett has been President and Chief Executive Officer and a director of our General Partner since his appointment effective February 21, 2019. Mr. Mallett's service in these capacities is on an interim basis. Mr. Mallett has also been the Chief Operations Officer of our General Partner since December 2015, and will continue to serve in this capacity while serving his interim appointments. Prior to joining our General Partner, Mr. Mallett served as Senior Vice President of Engineering for Enterprise, where he was responsible for the engineering, project management, sourcing and technical support functions supporting all of Enterprise’s pipeline and related plants. Mr. Mallett began his career with TEPPCO as a Project Engineer and spent the next three decades working with TEPPCO and successor entities in various engineering, transportation, and operations roles. At the end of 2006, Enterprise bought TEPPCO’s General Partner from Duke Energy Field Services, at which time Mr. Mallett was serving as SVP of Operations for TEPPCO. Post-merger, Mr. Mallett was named SVP-Environmental, Health and Safety. Mr. Mallett holds a Bachelor of Science in Mechanical Engineering from Prairie View A&M University and a Master of Business Administration from Houston Baptist University.

Marc D. Stratton has been the Executive Vice President and Chief Financial Officer of our General Partner since December 2018. Mr. Stratton joined Summit Investments as a founding member in 2009 and has held various senior

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management roles at the Company including, since 2015, Senior Vice President of Finance, Treasurer and Head of Investor Relations. Prior to joining the Company, Mr. Stratton served as a midstream infrastructure investment analyst at ING Investment Management and, prior to that, as Vice President of Project Finance at SunTrust Robinson Humphrey. Mr. Stratton has over 15 years of oil and gas industry experience in corporate finance and holds a Bachelor of Arts degree in Economics from Denison University.

Brock M. Degeyter has been the Executive Vice President, General Counsel, Chief Compliance Officer and Secretary of our General Partner since March 2015. Previously, he served as Senior Vice President and General Counsel from May 2012 until March 2015. Mr. Degeyter has been the Chief Compliance Officer of our General Partner since January 2014. Mr. Degeyter joined Summit Investments in January 2012 as Senior Vice President and General Counsel. Prior to joining Summit Investments, Mr. Degeyter worked in the corporate legal department for Energy Future Holdings (formerly TXU Corp.) from January 2007 through December 2011 where he served as Director of Corporate Governance and Senior Counsel. Prior to joining Energy Future Holdings, Mr. Degeyter was engaged in private practice with the firm of Correro Fishman Haygood Phelps Walmsley & Casteix LLP from May 2002 through December 2006. Mr. Degeyter is licensed to practice law in the states of Texas and Louisiana. Mr. Degeyter received a B.A. in Political Science from Louisiana State University and a J.D. from Loyola University College of Law in New Orleans.

Brad N. Graves has been the Executive Vice President and Chief Commercial Officer of our General Partner since March 2015. Previously, he served as Senior Vice President of Corporate Development from May 2012 until March 2015. In March 2013, he was promoted to Chief Commercial Officer. Prior to joining our General Partner, Mr. Graves was the Senior Vice President of Corporate Development of Summit Investments since April 2010. He was previously a Partner with Crestwood Midstream Partners, LLC from February 2008 until March 2010. Mr. Graves served as Executive Vice President—Business Development of Genesis Energy, LP from August 2006 until November 2007. He also served as Vice President—Offshore Commercial for Enterprise Products Partners L.P. ("Enterprise") from 2004 until August 2006. Prior to 2004, Mr. Graves served in a variety of commercial roles at Enterprise and GulfTerra Energy Partners, LP ("GulfTerra"), prior to its merger with Enterprise. In his roles with Enterprise and GulfTerra, Mr. Graves participated in numerous greenfield projects developed in the Gulf of Mexico. Mr. Graves earned a B.B.A. in Accounting from Texas A&M University and an MBA in Marketing and Finance from the University of Saint Thomas.

Louise E. Matthews has been Executive Vice President and Chief Administration Officer since February 21, 2019. Previously, she served as Senior Vice President, Human Resources and Corporate Communications from March 2016 to February 2019, and Vice President, Human Resources from May 2013 to March 2016. Prior to joining our General Partner, Ms. Matthews served as Senior Vice President at SunTrust Bank (“SunTrust”) from November 2010 to May 2013, leading the Human Resources organization supporting Enterprise Technology and Operations for all segments, including Wholesale, Investment Banking, Retail and Corporate Functions. While with SunTrust, Ms. Matthews also served as a certified executive coach. Prior to her time at SunTrust, Ms. Matthews served as Vice President of Human Resources with ING Investment Management. Ms. Matthews has also served as HR Director for Sprint, Integrated Health Services and Jekyll Island Authority. Ms. Matthews earned her Master of Business Administration and Bachelor of Business Administration from Georgia Southern University.

Matthew F. Delaney has served as a director of our General Partner since May 2016 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls Summit Investments, the sole owner of SMP Holdings, the entity that owns and controls our General Partner. Mr. Delaney has been an investment professional at Energy Capital Partners since 2011. Prior to joining Energy Capital Partners, Mr. Delaney worked in the Investment Banking Division at Morgan Stanley focusing on energy mergers and acquisitions. Mr. Delaney received a B.A. in Economics from Amherst College. Mr. Delaney was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry, and his financial and business expertise.

Peter Labbat has served as a director of our General Partner since August 2016 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls Summit Investments, the sole owner of SMP Holdings, the entity that owns and controls our General Partner. Mr. Labbat is Managing Partner of Energy Capital Partners and has been an investment professional at Energy Capital Partners since 2006. Prior to joining Energy Capital Partners, Mr. Labbat spent 13 years in Goldman Sachs' Investment Banking Division. He currently

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serves on the boards of Triton Power Holdings Limited, Sendero Midstream Partners, LP, Next Wave Energy Partners, LP and NCSG Crane & Heavy Haul Corp. Mr. Labbat received a B.A. in Economics from Georgetown University and an M.B.A. from the Wharton School at the University of Pennsylvania. Mr. Labbat was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Thomas K. Lane has served as director of our General Partner since May 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls Summit Investments, the sole owner of SMP Holdings, the entity that owns and controls our General Partner. Additionally, Mr. Lane serves as the chair of the Compensation Committee. Mr. Lane is Vice President of Energy Capital Partners has been a partner of Energy Capital Partners since 2005. Prior to joining Energy Capital Partners, Mr. Lane worked for 17 years in the Investment Banking Division at Goldman Sachs. As a Managing Director at Goldman Sachs, Mr. Lane had senior-level coverage responsibility for electric and gas utilities, independent power companies and merchant energy companies throughout the United States. Mr. Lane received a B.A. in economics from Wheaton College and an MBA from the University of Chicago. Mr. Lane was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Jerry L. Peters has served as a director of our General Partner since September 2012. Additionally, Mr. Peters served as the chair of the Conflicts Committee of our General Partner until Ms. Tomasky's appointment to the role in November 2012 and serves as the chair and financial expert of the Audit Committee of our General Partner. Mr. Peters served as the Chief Financial Officer of Green Plains Inc., a publicly traded vertically-integrated ethanol producer, from June 2007 until his retirement in September 2017. In 2015, Mr. Peters was appointed Chief Financial Officer and Director of the General Partner of Green Plains Partners LP, a publicly traded partnership engaged in fuel storage and transportation services. He retired from his role as Chief Financial Officer of the General Partner of Green Plains Partners LP in September 2017, but remains on the Board of Directors. Prior to joining Green Plains, Mr. Peters served as Senior Vice President—Chief Accounting Officer for ONEOK Partners, L.P. from May 2006 to April 2007, as Chief Financial Officer of ONEOK Partners, L.P. from July 1994 to May 2006, and in various senior management roles of ONEOK Partners, L.P. from 1985 to May 2006. Prior to joining ONEOK Partners, Mr. Peters was employed by KPMG LLP as a certified public accountant from 1980 to 1985. In October 2017, Mr. Peters joined the board of the general partner of USA Compression Partners LP and served as chair and financial expert of the audit committee thereof. Mr. Peters resigned from the board of the general partner of USA Compression Partners LP in March 2018. Mr. Peters received an MBA from Creighton University with an emphasis in finance and a B.S. in Business Administration from the University of Nebraska—Lincoln. Mr. Peters' extensive executive, financial and operational experience bring important and necessary skills to the Board of Directors.

Scott A. Rogan has served as a director of our General Partner since February 2014 and was appointed to the board in connection with his affiliation with Energy Capital Partners. Mr. Rogan joined Energy Capital Partners as a principal in February 2014. For five years prior to joining Energy Capital Partners, Mr. Rogan was employed by Barclays Capital ("Barclays") as a Managing Director working in the investment banking division of the natural resources group. Prior to its merger with Barclays in 2008, Mr. Rogan worked for over 10 years in investment banking for Lehman Brothers. Mr. Rogan received a bachelor's degree in business administration and a master's degree in professional accounting from the University of Texas at Austin as well as a master's degree in business administration from the University of Chicago. Mr. Rogan was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Jeffrey R. Spinner has served as a director of our General Partner since November 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners. Mr. Spinner has been an investment professional at Energy Capital Partners since 2006. Prior to joining Energy Capital Partners, Mr. Spinner worked in the Natural Resources Investment Banking Group at Banc of America Securities. Mr. Spinner received a B.S. in Economics from Duke University. Mr. Spinner was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Robert M. Wohleber has served as a director of our General Partner since August 2013. Mr. Wohleber served as Senior Vice President and Chief Financial Officer of Kerr-McGee Corporation, an oil and gas exploration and

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production company, from December 1999 to August 2006. From 1996 to 1998, he served as Senior Vice President and Chief Financial Officer of Freeport-McMoran, Inc., one of the largest phosphate fertilizer producers in the United States. He holds a B.B.A. from the University of Notre Dame and an M.B.A. from the University of Pittsburgh. Mr. Wohleber's extensive executive and financial experience in the oil and gas industry bring important and necessary skills to the Board of Directors.

Code of Business Conduct and Ethics

The Board of Directors of our General Partner has adopted a Code of Business Conduct and Ethics which sets forth SMLP’s policy with respect to business ethics and conflicts of interest. The Code of Business Conduct and Ethics is intended to ensure that the employees, officers and directors of SMLP and its General Partner conduct business with the highest standards of integrity and in compliance with all applicable laws and regulations. It applies to the employees, officers and directors of SMLP and its General Partner, including the principal executive officer, principal financial officer and principal accounting officer or controller, or persons performing similar functions (the "Senior Financial Officers"). The Code of Business Conduct and Ethics also incorporates expectations of the Senior Financial Officers that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. The Code of Business Conduct and Ethics is publicly available on our website under the "Corporate Governance" subsection of the “Investors” section at *www.summitmidstream.com* and is also available free of charge on written request to the Secretary at the Woodlands office address given under the "Contact" section on our website.

Corporate Governance Guidelines

Our Corporate Governance Guidelines, which are available on our website under the “Corporate Governance” subsection of the “Investors” section at *www.summitmidstream.com*, provide guidelines for the governance of the Company. The Corporate Governance Guidelines specifically provide, among other things, that (i) Jerry L. Peters, as the chairman of our Audit Committee, shall preside over any executive sessions, and (ii) interested parties may communicate directly with our independent directors by submitting a specially marked envelope to the Secretary of our General Partner.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires SMLP's directors and executive officers, and persons who own more than 10% of a registered class of our securities, to file with the SEC initial reports of ownership and reports of changes in ownership of SMLP's common units and other equity securities. Based on our records, we believe that all directors, executive officers and persons who own more than 10% of our common units have complied with the reporting requirements of Section 16(a).

Item 11. Executive Compensation.

This Compensation Discussion and Analysis (“CD&A”) provides information regarding the compensation of certain of our executive officers as reported in the Summary Compensation Table and other tables in this document. In this CD&A, we review the compensation decisions and rationale for those decisions relating to the person who served as our principal executive officer during the past fiscal year, the two persons who served as our principal financial officer during the past fiscal year, and our next three most highly compensated executive officers.

The following describes the material components of our executive compensation program for the following individuals, who are referred to as the "Named Executive Officers" or “NEOs”:

- Steven J. Newby, former President and Chief Executive Officer (1)
- Marc D. Stratton, Executive Vice President and Chief Financial Officer (2)
- Matthew S. Harrison, former Executive Vice President and Chief Financial Officer (3)
- Brock M. Degeyter, Executive Vice President, General Counsel, Chief Compliance Officer and Secretary
- Brad N. Graves, Executive Vice President and Chief Commercial Officer
- Leonard W. Mallett, President, Chief Executive Officer and Chief Operations Officer (4)

(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

(2) Mr. Stratton was appointed Executive Vice President and Chief Financial Officer effective December 7, 2018.

(3) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison's employment terminated on January 4, 2019.

(4) In connection with Mr. Newby's resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

The NEOs are employees of Summit Investments and executive officers of our General Partner. Certain of the NEOs split their working time between SMLP's business and their responsibilities for Summit Investments and its affiliates other than us. Under the terms of our Partnership Agreement, our General Partner determines the portion of the NEOs' compensation that is allocated to us. The percentage of total compensation allocated to us in 2018 for each NEO is as follows: 75% for Mr. Newby; 87.5% for Mr. Stratton; 90% for Mr. Degeyter; 92.5% for Mr. Graves; 95% for Mr. Mallett; 92.5% for Mr. Harrison.

The Compensation Committee provides oversight, administers and makes decisions regarding our compensation policies and plans.

Compensation Philosophy and Objectives

We seek to provide reasonable and competitive rewards to executives through compensation and benefit programs structured to:

• Attract and retain outstanding talent

• Drive achievement of short-term and long-term goals

• Reward successful execution of objectives

• Reinforce company culture and leadership competencies

• Align executives with the interests of our unitholders

We employ a pay-for-performance philosophy when designing executive compensation opportunities. Thus, a portion of an executive's target compensation is performance based through linkage to the achievement of financial and other measures deemed to be drivers in the creation of unitholder value. While the Compensation Committee does not set a specific target allocation among the elements of total direct compensation, a portion of the compensation opportunity available to each of our NEOs is, by design, tied to the Partnership's annual and long-term performance.

Compensation of Named Executive Officers

The Compensation Committee establishes the target total direct compensation of our executives and administers other benefit programs. The Compensation Committee engaged BDO USA, L.L.P. as its independent compensation consultant (the “Compensation Consultant”). The Compensation Consultant provides the Compensation Committee with data, analysis and advice on the structure and level of executive compensation. The Compensation Consultant participates in Compensation Committee meetings and executive sessions of the Compensation Committee meetings as requested. The Compensation Consultant may work with our management on various matters for which the Compensation Committee is responsible. However, the Compensation Committee, not management, directs the activities of the Compensation Consultant. We consider the Compensation Consultant to be independent of the Partnership according to current NYSE listing requirements and SEC guidance.

Partnership management, in consultation with the Compensation Committee chair and the Compensation Consultant, prepares materials for the Compensation Committee relevant to matters under consideration by the Compensation Committee, including market data provided by the Compensation Consultant and recommendations of our Chief Executive Officer (the "CEO") regarding compensation of the other executives. The Compensation Committee works directly with the Compensation Consultant on our CEO’s compensation as required.

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Based on market data which we use as a reference, we believe compensation of our NEOs is reasonably competitive with opportunities available to officers holding similar positions at comparable midstream companies. We seek to set compensation levels for each component of total direct compensation based on our assessment of market practices at or near the median. The Compensation Committee adjusts target compensation for each NEO above or below the median, taking into consideration experience, performance, internal equity and other relevant circumstances.

During the Compensation Committee’s annual review of executive compensation, the Compensation Consultant provided the Compensation Committee with an analysis of positions comparable to the NEOs at peer companies. To develop these exhibits, information from peer company public filings was compiled, including public company proxy statements and annual reports on Form 10-K. The peer group used for 2018 executive compensation consisted of publicly traded midstream companies with whom we compete for executive talent.

The peer group comprised the following companies:

| | |
|---|---|
| American Midstream Partners, LP | Genesis Energy, L.P. |
| Boardwalk Pipeline Partners, LP | Noble Midstream Partners, LP |
| Crestwood Equity Partners LP | NuStar Energy L.P. |
| DCP Midstream, LP | SemGroup Corporation |
| Enable Midstream Partners, LP | Tallgrass Energy Partners LP |
| EnLink Midstream Partners, LP | Targa Resources Corp. |
| EQM Midstream Partners, LP | |

The compensation analysis encompassed the primary components of total direct compensation, including annual base salary, annual short-term incentive and long-term incentive awards for the NEOs of these peer group companies. The Compensation Committee considered the information provided to ascertain whether the compensation of our NEOs is aligned with our compensation philosophy and competitive with the compensation for executive officers of the peer group companies. The Compensation Committee reviewed the compensation analysis to confirm that our compensation programs were supporting a competitive total compensation approach that emphasizes incentive-based compensation and appropriately rewards achievement of our objectives. For 2018, the target total direct compensation for the NEOs as set by the Compensation Committee is summarized below. Each element is further discussed in this CD&A.

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**Components of Executive Compensation**

| Name and Principal Position | Base Salary ($) | 2018 Target Annual Bonus: Percent of Base Salary (%) | 2018 Target LTIP Award: Percent of Base Salary (%) | 2018 LTIP Target Award Value ($) | 2018 Target Total Direct Compensation ($) |
|---|---|---|---|---|---|
| Steven J. Newby (1) Former President and Chief Executive Officer | 612,000 | 150 | 250 | 1,530,000 | 3,060,000 |
| Marc D. Stratton (2) Executive Vice President and Chief Financial Officer | 264,894 | 75 | 85 | 225,000 | 684,669 |
| Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary | 373,000 | 100 | 150 | 559,500 | 1,305,500 |
| Brad N. Graves Executive Vice President and Chief Commercial Officer | 398,000 | 100 | 150 | 597,000 | 1,393,000 |
| Leonard W. Mallett (3) President, Chief Executive Officer and Chief Operations Officer | 384,000 | 100 | 150 | 576,000 | 1,344,000 |
| Matthew S. Harrison (4) Former Executive Vice President and Chief Financial Officer | 424,000 | 100 | 150 | 636,000 | 1,484,000 |

(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

(2) Mr. Stratton was appointed Executive Vice President and Chief Financial Officer effective December 7, 2018. Because Mr. Stratton was not an NEO at the beginning of the year, the Compensation Committee played no role in setting his target compensation for 2018. Accordingly, this table, and subsequent tables restating data from this table, set forth Mr. Stratton's 2018 target compensation as set by our management.

(3) In connection with Mr. Newby's resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

(4) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison's employment terminated on January 4, 2019.

The primary elements of compensation for the NEOs are base salary, annual incentive compensation and long-term equity-based compensation awards. The NEOs also receive certain retirement, health, welfare and additional benefits.

Base Salary. The base salaries for our NEOs are reviewed annually by the Compensation Committee. Base salaries for our NEOs have generally been set at levels deemed necessary to attract and retain individuals with superior talent.

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The base salaries of our NEOs, a portion of which are allocated to and reimbursed by Summit Investments and its affiliates other than us, are set forth in the following table:

| Name and Principal Position | 2018 Base Salary ($) |
|---|---|
| Steven J. Newby (1) | |
| Former President and Chief Executive Officer | 612,000 |
| Marc D. Stratton (2) | |
| Executive Vice President and Chief Financial Officer | 264,894 |
| Brock M. Degeyter | |
| Executive Vice President, General Counsel, Chief Compliance Officer and Secretary | 373,000 |
| Brad N. Graves | |
| Executive Vice President and Chief Commercial Officer | 398,000 |
| Leonard W. Mallett (3) | |
| President, Chief Executive Officer and Chief Operations Officer | 384,000 |
| Matthew S. Harrison (4) | |
| Former Executive Vice President and Chief Financial Officer | 424,000 |

(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

(2) Mr. Stratton was appointed Executive Vice President and Chief Financial Officer effective December 7, 2018.

(3) In connection with Mr. Newby's resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

(4) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison's employment terminated on January 4, 2019.

Annual Incentive Compensation.  We provide an annual incentive bonus ("annual bonus") to drive the achievement of key business results and to recognize NEOs based on their contributions to those results. The annual bonus plan is a cash-based incentive plan. Incentive amounts are intended to provide total cash compensation near the market range for executive officers in comparable positions when target performance is achieved. Annual bonus compensation levels are set above or below the market range to reflect actual performance results as appropriate when performance is greater or less than expectations. Annual bonus payouts may range from 0% to 200% of the target opportunity and may be adjusted at the discretion of the Compensation Committee.

In March 2018, the Compensation Committee established the 2018 annual bonus plan target opportunities as a percentage of base salary for our NEOs. The 2018 targets for Messrs. Harrison, Mallett, Graves and Degeyter were 100% of their base salaries, while Mr. Newby's 2018 target was 150%. Because Mr. Stratton was not an NEO in March 2018, the Compensation Committee played no role in establishing his 2018 annual bonus plan target. Instead, Mr. Stratton's target bonus was set by our management at 75% of his base salary.

| Name and Principal Position | 2018 Target Annual Bonus: Percent of Base Salary (%) | 2018 Target Bonus: Dollar Value ($) |
|---|---|---|
| Steven J. Newby (1)<br>Former President and Chief Executive Officer | 150 | 918,000 |
| Marc D. Stratton (2)<br>Executive Vice President and Chief Financial Officer | 75 | 194,775 |
| Brock M. Degeyter<br>Executive Vice President, General Counsel, Chief Compliance Officer and Secretary | 100 | 373,000 |
| Brad N. Graves<br>Executive Vice President and Chief Commercial Officer | 100 | 398,000 |
| Leonard W. Mallett (3)<br>President, Chief Executive Officer and Chief Operations Officer | 100 | 384,000 |
| Matthew S. Harrison (4)<br>Former Executive Vice President and Chief Financial Officer | 100 | 424,000 |

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(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

(2) Mr. Stratton was appointed Executive Vice President and Chief Financial Officer effective December 7, 2018.

(3) In connection with Mr. Newby's resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

(4) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison's employment terminated on January 4, 2019.

In 2018, quantitative factors, as reflected in the corporate scorecard applicable to the senior leadership team (the "SLT Scorecard") determined at least one-half of the annual bonus for Messrs. Degeyter, Graves and Mallett while their respective business unit scorecards accounted for the remainder. (The annual bonus amounts determined based on these scorecards were subject to further adjustments as explained below). The annual bonus paid to Mr. Stratton was determined based on business unit scorecard results, subject to further adjustments as explained below. The SLT Scorecard contained four factors, each of which are considered by the Board of Directors and management as key indicators of the successful execution of our business plan. Those factors were (i) adjusted EBITDA, (ii) distributable cash flow per unit, (iii) controllable expense metric and (iv) health, safety, environmental and regulatory goals.

The annual bonuses paid to Messrs. Newby and Harrison were approved by the Board and determined in accordance with their employment agreements, as further described below.

In February 2019, the Compensation Committee and the Board of Directors reviewed the SLT Scorecards for 2018 and determined the level of achievement of each key factor. We exceeded two of our targets: our controllable expense metric and our health, safety, environmental and regulatory goals. We did not meet our adjusted EBITDA target or our distributable cash flow per unit target. These results yielded a calculated SLT Scorecard result of 105% of target for the portion of the NEOs' annual bonuses based on SLT Scorecard results.

In addition to corporate and business unit results reported on scorecards, additional considerations are applied at the discretion of the CEO, the Compensation Committee or the Board of Directors that may affect the actual annual bonus earned. Those considerations include judgments regarding overall company performance and business events, industry climate and performance, the market for executive talent, demonstrated leadership capabilities and progress on strategic initiatives. Each NEO's bonus amount, as reflected below, is adjusted up or down in recognition of exceeding, or in some cases, falling short of certain business unit goals and objectives.

Mr. Degeyter's annual bonus payout reflects consideration for the performance results of the legal business unit. The total amount awarded to Mr. Degeyter reflects 105% of his target annual bonus in 2018, or $392,000.

Mr. Graves' annual bonus payout reflects consideration for the performance results of the corporate development business unit. The total amount awarded to Mr. Graves reflects 100% of his target annual bonus in 2018, or $398,000.

Mr. Mallett's annual bonus payout reflects consideration for the combined performance results of enterprise technology, engineering, construction and operations and health, safety, environmental and regulatory business units.

The total amount awarded to Mr. Mallett reflects 100% of his target annual bonus in 2018, or $384,000.

Mr. Stratton's annual bonus payout reflects consideration for the combined performance results of the finance and investor relations business unit. Mr. Stratton was paid 100% of his target annual bonus for 2018, plus an additional sum in recognition of Mr. Stratton's extraordinary leadership during the CFO transition in the fourth quarter of 2018. The total amount awarded to Mr. Stratton was $291,000.

The Board approved a bonus for Mr. Newby, to be paid in connection with his departure, equal to 100% of his target bonus for 2018, or $918,000, plus a prorated 2019 target bonus for the period of time he was an employee of Summit Investments in 2019, in accordance with the terms of his employment agreement.

The Board approved a bonus for Mr. Harrison, paid upon his departure, equal to 100% of his target bonus for 2018, or $424,000, plus a prorated 2019 target bonus for the period of time he was an employee of Summit Investments in 2019, in accordance with the terms of his employment agreement.

Only a portion of the annual bonus amounts are allocated to and reimbursed by the Partnership. For a discussion of the cost allocation methodology, please refer to "Reimbursement of Expenses from General Partner" in Item 13. Certain Relationships and Related Transactions, and Director Independence. Based on the foregoing discussion, the annual bonus awards to be paid in March 2019 (or earlier in the case of Mr. Harrison) to our NEOs for 2018 performance are as follows:

| Name and Principal Position | 2018 Annual Bonus Payout ($) |
| --- | --- |
| Steven J. Newby (1) | |
| Former President and Chief Executive Officer | 918,000 |
| Marc D. Stratton (2) | |
| Executive Vice President and Chief Financial Officer | 291,000 |
| Brock M. Degeyter | |
| Executive Vice President, General Counsel, Chief Compliance Officer and Secretary | 392,000 |
| Brad N. Graves | |
| Executive Vice President and Chief Commercial Officer | 398,000 |
| Leonard W. Mallett (3) | |
| President, Chief Executive Officer and Chief Operations Officer | 384,000 |
| Matthew S. Harrison (4) | |
| Former Executive Vice President and Chief Financial Officer | 424,000 |

(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

(2) Mr. Stratton was appointed Executive Vice President and Chief Financial Officer effective December 7, 2018.

(3) In connection with Mr. Newby's resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

(4) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison's employment terminated on January 4, 2019.

Long-Term Equity-Based Compensation Awards. Our General Partner approved the SMLP LTIP pursuant to which eligible officers (including the NEOs), employees, consultants and directors of our General Partner and its affiliates are eligible to receive awards with respect to our equity interests, thereby linking the recipients' compensation directly to the value of SMLP's common units and enhancing our ability to attract and retain superior talent. The SMLP LTIP provides for the grant, from time to time at the discretion of the Board of Directors or Compensation Committee, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards.

The SMLP LTIP is designed to promote our interests, as well as the interests of our unitholders, by aligning the interests of our eligible employees (including the NEOs) and directors with those of common unitholders, as well as by strengthening our ability to attract, retain and motivate qualified individuals to serve as directors and employees.

SMLP LTIP award guidelines for NEOs are designed to attract, retain and motivate the NEOs and were determined using the Compensation Consultant's analysis for individuals in comparable positions and an analysis of the scope of their roles and duties. These guidelines set an annual equity award target in the amount of 150% of base salary for Messrs. Harrison, Degeyter, Graves and Mallett. Mr. Newby's targeted annual equity award is 250% of his base salary. Because Mr. Stratton did not become an NEO until December 2018, the Compensation Committee did not set an annual equity award target for Mr. Stratton. Instead, Mr. Stratton's target annual equity award was set by our management.

March 2018 Equity Grants. Effective March 15, 2018, based on the recommendation of the Compensation Committee, the Board of Directors approved a grant of phantom units to the NEOs. The underlying phantom units vest ratably over a three-year period. Holders of phantom units are entitled to distribution equivalent rights for each phantom unit, providing for a lump sum payment equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. The Compensation Committee selected equity awards that vest contingent on continued service to foster increased unit ownership by the NEOs and as a retention incentive for continued employment with the Partnership.

All SMLP LTIP grants to our NEOs are subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the NEO's employment other than for cause, (ii) a termination of the NEO's employment by the officer for good reason (as defined in the NEO's employment agreement), (iii) a termination of the NEO's employment by reason of the NEO's death or disability or (iv) a Change in Control (as defined in the applicable award agreement).

To calculate the number of phantom units granted to each NEO, the Compensation Committee determined the dollar amount of the long-term incentive compensation award, and then granted the number of phantom units that had a fair market value equal to that amount as of market close on the date of the grant. Phantom unit awards granted in March 2018 were as follows:

| Name and Principal Position | 2018 Target LTIP Award: Percent of Base Salary (%) | 2018 Phantom Units Awarded (#) | 2018 SMLP LTIP Award Value ($) |
|---|---|---|---|
| Steven J. Newby (1) | | | |
| President and Chief Executive Officer | 250 | 101,639 | 1,550,000 |
| Marc D. Stratton (2) | | | |
| Executive Vice President and Chief Financial Officer | 85 | 14,754 | 225,000 |
| Brock M. Degeyter | | | |
| Executive Vice President, General Counsel, Chief Compliance Officer and Secretary | 150 | 40,983 | 625,000 |
| Brad N. Graves | | | |
| Executive Vice President and Chief Commercial Officer | 150 | 40,983 | 625,000 |
| Leonard W. Mallett (3) | | | |
| President, Chief Executive Officer and Chief Operations Officer | 150 | 40,983 | 625,000 |
| Matthew S. Harrison (4) | | | |
| Former Executive Vice President and Chief Financial Officer | 150 | 44,262 | 675,000 |

(1) Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby’s employment will terminate on February 28, 2019.

(2) Because Mr. Stratton did not become an NEO until December 2018, the Compensation Committee did not establish a 2018 target LTIP award for Mr. Stratton. Mr. Stratton’s 2018 target LTIP award was determined by our management.

(3) In connection with Mr. Newby’s resignation, on February 21, 2019, Mr. Mallett was appointed President and Chief Executive Officer on an interim basis. Mr. Mallett will continue to serve as Chief Operations Officer during the interim period.

(4) Mr. Harrison resigned from his position as Executive Vice President and Chief Financial Officer effective December 7, 2018. Mr. Harrison’s employment terminated on January 4, 2019.

Retirement, Health and Welfare and Additional Benefits. The NEOs are eligible to participate in such employee benefit plans and programs as we offer to our employees, subject to the terms and eligibility requirements of those plans.

401(k) Plan. The NEOs are eligible to participate in a tax qualified 401(k) defined contribution plan to the same extent as all of our other employees. In 2018, we made a fully vested matching contribution on behalf of each of the 401(k) plan's participants up to 5% of such participant's eligible salary for the year.

Health Savings Account ("HSA") Program. The NEOs are eligible to participate in a tax qualified health savings account ("HSA") if they are enrolled in the available high-deductible health plan. The HSA is a tax-free savings account owned by an individual and can be used to pay for current or future qualified medical expenses. Participants determine how much to contribute, when and how to spend the money on eligible medical expenses, and how to invest the balance. The balance remains in the account and is not subject to forfeiture. The Partnership makes annual contributions to all HSA-eligible employees who enroll in and contribute to an HSA. In 2018, Summit Investments made tax-free HSA contributions of $1,943 to Messrs. Harrison and Graves and $1,838 to Mr. Stratton.

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Deferred Compensation Plan. Effective July 1, 2013, the Board approved a Deferred Compensation Plan (the "DCP"), which is a defined contribution supplemental executive retirement plan established to attract and retain key employees and directors by providing participants with an opportunity to defer receipt of a portion of their salary, bonus and other specified compensation. The DCP is an unfunded, nonqualified plan that provides each participant in the plan with benefits based on the participant's notional account balance at the time of retirement or termination. Each participant allocates deferrals among designated mutual fund investments to serve as indices for the purpose of determining notional investment gains and losses to each participant's account.

Deferrals of SMLP LTIP grants and other equity-based awards are allocated to the Summit Midstream Partners, LP Unit Fund (the "Unit Fund"). The Unit Fund consists of notional common units in SMLP, with each unit approximating the value of one common unit of SMLP. The distribution equivalent rights associated with any SMLP LTIP grant may be allocated to any available investment option, other than the Unit Fund. Mr. Newby elected to defer a portion of his compensation comprised of LTIP units scheduled to vest on March 15, 2018 under the DCP.

The DCP is filed as Exhibit 4.3 to the Partnership's Form S-8 Registration Statement dated June 28,2013.

Tax Preparation and Advisory Services. Pursuant to the terms of their employment agreements, all NEOs are entitled to reimbursement for tax preparation and advisory services expenses of up to $12,000 per year. Expenditures for these additional benefits are disclosed by individual in footnote 4 to the Summary Compensation Table.

Employment and Severance Arrangements. Our NEOs each have employment agreements with Summit Investments (the "Company"). Elements of the NEOs' total direct compensation are subject to periodic review and may be adjusted accordingly by the Compensation Committee.

Mr. Newby's employment agreement, which was amended and restated on July 20, 2015 and took effect on August 13, 2015, was subsequently amended effective August 4, 2017 to extend the initial term to March 1, 2020. Following the expiration of the initial term, the employment agreement is automatically extended for successive one-year periods, unless either party gives notice of non-extension to the other no later than 30 days prior to the expiration of the then-applicable term. Mr. Newby's employment agreement provides for an annual base salary of $600,000 ($612,000 effective March 2018), and a performance-based bonus ranging from 0% to 300% of base salary, with a target of 150% of base salary. Mr. Newby is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Mr. Newby for good reason, or by the Company without cause or as a result of a non-extension of the term by the Company, or due to death or disability. In addition, Mr. Newby's employment agreement provides for reimbursement of certain business expenses incurred in connection with his employment, including tax preparation and advisory services of up to $12,000 per year. Mr. Newby is also entitled to reimbursement for the cost of an annual executive physical health examination.

Mr. Newby's employment agreement provides for a cash severance payment upon a termination resulting from a non-extension of the term by the Company, by the Company without cause or by Mr. Newby for good reason, which is defined generally as Mr. Newby's termination of employment within two years after the occurrence of (i) a material diminution in Mr. Newby's authority, duties or responsibilities, (ii) a material diminution in Mr. Newby's base salary, target bonus (as a percentage of base salary) or annual bonus range (as a percentage of base salary), (iii) a material change in the geographic location at which Mr. Newby must perform his services under the agreement, (iv) a change in Mr. Newby's reporting relationship resulting in Mr. Newby no longer reporting directly to the Board of Directors of the Company or the General Partner, or (v) any other action or inaction that constitutes a material breach of the employment agreement by the Company (each a "Qualifying Termination"). In the event of a Qualifying Termination, Mr. Newby's severance payment will be equal to two and one-half times the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year.

Following any termination of employment other than one resulting from non-extension of the term, Mr. Newby's employment agreement provides that he will be subject to a one-year post-termination non-competition covenant, and, following any termination of employment, Mr. Newby will be subject to a one-year post-termination non-solicitation covenant. If Mr. Newby's employment terminates as a result of a non-extension of the term, the Company may choose to subject him to a non-competition covenant for up to one year post-termination. If the Company exercises this "noncompete option" following a non-extension of the term by Mr. Newby, then Mr. Newby would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, the Company has agreed to pay the out-of-pocket premium cost to continue Mr. Newby's medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provides benefits coverage.

Mr. Newby's employment agreement also provides that all equity awards granted to Mr. Newby under the LTIP and held by him as of immediately prior to a change in control of us will become fully vested immediately prior to the change in control.

Mr. Newby's employment agreement provides that, if any portion of the payments or benefits provided to Mr. Newby would be subject to the excise tax imposed in connection with Section 4999 of the Internal Revenue Code, then the payments and benefits will be reduced if such reduction would result in a greater after-tax payment to Mr. Newby.

Mr. Newby resigned from his position as President and Chief Executive Officer effective February 21, 2019. Mr. Newby's employment will terminate on February 28, 2019.

The other NEOs' employment agreements are substantially the same as Mr. Newby's, except for the following:

- Each of the other NEOs is entitled to a severance payment in the event of a Qualifying Termination equal to one and one-half times the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year.
- Each of the other NEOs is entitled to a performance-based bonus ranging from 0% to 200% of base salary, with a target of 100% of base salary.
- The other NEOs are not entitled to be reimbursed for the cost of an annual executive physical.
- Mr. Stratton's base salary is $350,000, and the Initial Term of his employment agreement ends on March 31, 2021.
- Mr. Degeyter's base salary is $373,000 (increased to $380,000 effective March 2019), and the Initial Term of his employment agreement ends on March 1, 2020.
- Mr. Graves' base salary is $398,000 (increased to $400,000 effective March 2019), and the Initial Term of his employment agreement ends on March 1, 2020.
- Mr. Mallett's base salary is $384,000 (increased to $400,000 effective March 2019), and the Initial Term of his employment agreement ends on March 1, 2020.
- Additionally, as an inducement to accept the position of Chief Operations Officer of the Company, on December 1, 2015, Mr. Mallett received a one-time grant of phantom units valued at $1,600,000, pursuant to a standalone phantom unit award agreement. The phantom units vested ratably over a three-year period, which concluded on December 1, 2018.

Risk Assessment Relative to Compensation Programs. The Compensation Committee manages risk as it relates to our compensation plans, programs and structure (collectively, our "compensation practices"). The Compensation Committee meets with management to review whether any aspect of our compensation practices creates incentives for our employees to take inappropriate risks that could materially adversely affect the Partnership. Accordingly, we believe that the compensation practices for our NEOs and other employees are appropriately structured and do not pose a material risk to the Partnership. We believe these compensation practices are designed and implemented in a manner that does not promote excessive risk-taking that could damage the value of the Partnership or provide compensatory rewards for inappropriate decisions or behavior.

Compensation Committee Report. The Compensation Committee has reviewed and discussed this CD&A with our management and, based on such review and discussion, has recommended to the Board that the CD&A be included in the Annual Report on Form 10-K.

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**Summary Compensation Table for 2018, 2017 and 2016**

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2018, 2017 and 2016 and allocated to us by our General Partner. Under the terms of our Partnership Agreement, our General Partner determines the portion of the NEOs' compensation that is allocated to us. For a discussion of the cost allocation methodology, please refer to "Agreements with Affiliates—Reimbursement of Expenses from General Partner" in Item 13. Certain Relationships and Related Transactions, and Director Independence.

| Name and Principal Position | Year | Salary ($) (1) | Bonus ($) | Equity Awards ($) (2) | Non-Equity Incentive Plan Compensation ($) (3) | All Other Compensation ($) (4) | Total ($) |
|---|---|---|---|---|---|---|---|
| Steven J. Newby (5) | 2018 | 459,000 | — | 1,550,000 | 688,500 | 34,487 | 2,731,987 |
| Former President and Chief Executive Officer | 2017 | 540,000 | — | 1,950,000 | 769,500 | 36,918 | 3,296,418 |
| | 2016 | 517,500 | — | 1,750,000 | 900,000 | 37,020 | 3,204,520 |
| Marc D. Stratton (6) | 2018 | 231,782 | — | 225,000 | 254,625 | 31,700 | 743,107 |
| Executive Vice President and Chief Financial Officer | | | | | | | |