Summit Midstream Partners, LP
Form 10-K
February 26, 2018
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, 2017

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	(I.R.S. Employer
incorporation or organization)	Identification No.)
1790 Hughes Landing Blvd, Suite 500	
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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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	(Do not check if a smaller reporting company)	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, 2017, was $928,653,216.

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 73,085,996 common units and 1,490,999 general partner units outstanding at February 16, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

None

Table of Contents

TABLE OF CONTENTS

Table of Contents

ORGANIZATIONAL CHART

Table of Contents

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 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 from SMP Holdings
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 oil or as a free gas cap above the 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 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
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

Table of Contents

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
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
NGL	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
Polar and Divide	the Polar and Divide system; collectively Polar Midstream and Epping

Polar and Divide Drop Down	the Partnership's May 18, 2015 acquisition of all of the issued and outstanding membership interests in Polar Midstream and Epping from SMP Holdings
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 Drop Down	the Partnership's March 18, 2014 acquisition of all of the issued and outstanding membership interests in Red Rock Gathering from SMP Holdings
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

Table of Contents

SEC	Securities and Exchange Commission
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) unit-based and noncash compensation, (vi) the change in the Deferred Purchase Price Obligation fair value, (vii) early extinguishment of debt expense, (viii) impairments and (ix) 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 Utica	Summit Midstream Utica, LLC
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 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 basin	a basin where natural gas or crude oil production is developed from unconventional 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

Table of Contents

PART I

Item 1. Business.

SMLP is a Delaware limited partnership that completed its IPO in October 2012. 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 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, 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;
- 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;
- 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;
- 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;
- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas;

Table of Contents

- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia; and
- Summit Permian, an associated natural gas gathering and processing system under development in the northern Delaware Basin in southeastern New Mexico.

The systems that we operate and/or have a 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 are as follows:

- XTO Energy Inc. ("XTO") and Ascent, the key customers for Summit Utica;
- Gulfport Energy Corporation ("Gulfport") and Ascent Resources - Utica, LLC ("Ascent"), the key customers for Ohio Gathering;
- Whiting Petroleum Corp. ("Whiting") and SM Energy Company ("SM Energy"), the key customers for Polar and Divide;
- Hess Corp. ("Hess"), the key customer for Tioga Midstream;
- Oasis Petroleum, Inc. ("Oasis") and a large U.S. independent crude oil and natural gas company, the key customers for Bison Midstream;
- Caerus Oil & Gas LLC ("Caerus") and Terra Energy Partners LLC ("Terra"), the key customers for Grand River;
- Fifth Creek Energy Operating Company, LLC ("Fifth Creek") and a large U.S. independent crude oil and natural gas company, the key customers for Niobrara G&P;
- Total Gas & Power North America, Inc. ("Total"), the key customer for DFW Midstream;
- Antero Resources Corp. ("Antero"), the key customer for Mountaineer Midstream; and
- XTO, the key customer of Summit Permian, which is currently under development.

We believe that the systems we operate and/or have significant ownership interests in are positioned for growth through increased utilization and further development. We intend to continue expanding our operations and diversifying our geographic footprint through asset acquisitions from third parties. We also intend to grow our business through the execution of new, and the expansion of existing, strategic partnerships with large producers to provide midstream services for their upstream exploration and production projects. In addition, we may participate in asset acquisitions with Summit Investments, although (i) Summit Investments has no current direct ownership interest in any operating assets, (ii) Summit Investments has no obligation to us to offer any assets that it may acquire or participate in any asset acquisitions that we may make and (iii) we have no obligation to acquire any assets offered.

Our financial results are primarily driven by volume throughput across our gathering systems and expense management. During 2017, aggregate natural gas volume throughput averaged 1,748 MMcf/d and crude oil and produced water volume throughput averaged 75.2 Mbbl/d. A substantial majority of the volumes that we gather, treat and/or process have a fixed-fee rate structure thereby enhancing the stability of our cash flows by providing a revenue stream that is not directly subject to commodity price risk. Activities that expose us to direct commodity price risk 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 system customers and (iv) the sale of condensate we retain from our gathering services at Grand River. During the year ended December 31, 2017, less than 14% of our revenues were exposed to direct commodity price risk.

In addition, the vast majority of our gathering and/or processing agreements include AMIs. Our AMIs cover approximately 3.3 million acres in the aggregate, which includes more than 0.8 million acres in 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

8

Table of Contents

processed, either on a monthly, quarterly or annual 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 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, 2017, we had remaining MVCs totaling 2.6 Tcfe. Our MVCs have a weighted-average remaining life of 7.4 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1.0 Bcfe/d through 2022.

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 amounts 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.

Financial Information About Segments. As of December 31, 2017, our reportable segments and their respective gathering systems were:

- the Utica Shale, which is served by Summit Utica;
- Ohio Gathering, which includes our ownership interest in OGC and OCC;
- the Williston Basin, which includes Polar and Divide, Tioga Midstream and Bison Midstream;
- the Piceance/DJ Basins, which includes Grand River and Niobrara G&P;
- the Barnett Shale, which includes DFW Midstream; and
- the Marcellus Shale, which includes Mountaineer Midstream;

Our reportable segments reflect the way in which (i) we manage our operations and (ii) management uses the reported financial information to make decisions and allocate resources in connection therewith. The primary assets of our reportable segments consist of gathering systems and the related property, plant and equipment and intangible assets with the exception of the Ohio Gathering reportable segment, which holds our ownership interest in OGC and OCC.

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Property, plant and equipment, net	$1,795,129	$1,853,671	$1,812,783
Intangible assets, net	301,345	421,452	461,310

For additional information on our reportable segments, see the "Results of Operations—Segment Overview for the Years Ended December 31, 2017, 2016 and 2015" section included in the Item 7. MD&A and Note 3 to the consolidated financial statements. For additional information on revenue and accounts receivable concentrations, see the "Liquidity and Capital Resources—Credit and Counterparty Concentration Risks" section included in Item 7. MD&A and Notes 3 and 10 to the consolidated financial statements. For additional information on long-lived assets, see Notes 4 and 5 to the consolidated financial statements.

Our Sponsor and Summit Investments. Energy Capital Partners, together with its affiliated funds, is a private equity firm with over $13.0 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

Table of Contents

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.

In December 2015, Energy Capital Partners approved a unit purchase program of up to $100.0 million of SMLP common units (the "Purchase Program"). A wholly owned subsidiary of Summit Investments acquired 151,160 common units and Energy Capital Partners acquired 5,915,827 common units under the Purchase Program. The Purchase Program concluded in June 2016.

Business Strategies

Our principal business strategy is to increase the amount of cash distributions we make to our unitholders over time. Our plan for continuing to execute this strategy includes the following key components:

- Maintaining our focus on fee-based revenue with minimal direct commodity price exposure. As we expand our business, we intend to maintain our focus on providing midstream energy services under fee-based arrangements. Our midstream services are provided under primarily long-term and fee-based contracts with original terms of up to 25 years. We believe that our focus on fee-based revenues with minimal direct commodity price exposure is essential to maintaining stable cash flows.
- Capitalizing on organic growth opportunities to maximize throughput on our existing systems. We intend to continue to leverage our management team's expertise in constructing, developing and optimizing our midstream assets to grow our business through organic development projects. We believe that our broad and geographically diverse operating footprint provides us with a competitive advantage to pursue organic development projects that are designed to extend our geographic reach, diversify our customer base, expand our midstream service offerings, increase the number of our hydrocarbon receipt points and maximize volume throughput.
    - Diversifying our asset base by expanding our midstream service offerings to new geographic areas. Our gathering operations in the Utica, Bakken, Barnett and Marcellus shale plays and the Piceance and DJ basins currently represent our core business. We intend to pursue opportunities to diversify our operations into other geographic regions through both greenfield development projects and acquisitions from third parties. For example, in the third quarter of 2017, we began developing Summit Permian, an associated natural gas gathering and processing system, in the northern Delaware Basin in southeastern New Mexico.
- Partnering with producers to provide midstream services for their development projects in high-growth, unconventional resource plays. We seek to promote commercial relationships with established and well-capitalized producers that are willing to serve as key customers and commit to long-term MVCs and/or AMIs. We will continue to pursue partnership opportunities with established producers to develop new midstream energy infrastructure in unconventional resource basins that we believe will complement our existing assets and/or enhance our overall business by facilitating our entry into new basins. These opportunities generally consist of a strategic acreage position in an unconventional resource play that is well-positioned for accelerated production but has limited existing midstream energy infrastructure to support such growth.

Competitive Strengths

We believe that we will be able to execute the components of our principal business strategy successfully because of the following competitive strengths:

- Strategically located assets in core areas of prolific unconventional resource basins supported by partnerships with large producers. We believe our assets are strategically positioned within the core areas

of six established unconventional resource basins including Summit Permian currently under development. The geologic formations in the basins served by our assets have either relatively low drilling

Table of Contents

and completion costs, highly economic production profiles, or a combination of both, which incentivize producers to develop more actively than in more marginal areas.

- Fee-based revenues underpinned by long-term contracts with AMIs and MVCs. A substantial majority of our revenues for the year ended December 31, 2017 was generated under long-term and fee-based gathering and processing agreements. We believe that long-term, fee-based gathering and processing agreements enhance the stability of our cash flows by limiting our direct commodity price exposure.
    - Capital structure and financial flexibility. At December 31, 2017, we had $1.06 billion of total indebtedness outstanding (see Notes 1, 2 and 9 to the consolidated financial statements), and the unused portion of our $1.25 billion Revolving Credit Facility totaled $989.0 million. Under the terms of our Revolving Credit Facility, our total leverage ratio (total net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) was 3.62 to 1.0 at December 31, 2017, which compares with the total leverage ratio upper limit of not more than 5.5 to 1.0 (as defined in the credit agreement).
    - Relationship with a large and committed financial sponsor. Our Sponsor is an experienced energy investor with a proven track record of making substantial, long-term investments in high-quality energy assets. In addition to its direct investment in Summit Investments, Energy Capital Partners purchased our common units in open market transactions commencing in December 2015 and concluding in June 2016. We believe that the relationship with and support of our Sponsor is a competitive advantage as it brings not only significant financial and management experience, but also numerous relationships throughout the energy industry that we believe will continue to benefit us as we seek to grow our business.
- Experienced management team with a proven record of asset acquisition, construction, development, operations and integration expertise. Our board members and senior leadership team have extensive energy experience (see Item 10. Directors, Executive Officers and Corporate Governance—Directors and Executive Officers) and a proven track record of identifying, consummating, financing and integrating significant acquisitions in addition to partnering with major producers to construct and develop midstream energy infrastructure.

Our Midstream Assets

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

- the Utica Shale, which is 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 Piceance/DJ Basins, which is served by Grand River and Niobrara G&P;
- the Barnett Shale, which is served by DFW Midstream;
- the Marcellus Shale, which is served by Mountaineer Midstream; and
- the Delaware Basin, which is currently under development and will be served by Summit Permian.

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, 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

11

Table of Contents

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 systems. 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.

Under certain of our gathering agreements, we have agreed to construct pipeline laterals to connect our gathering systems to pad sites located within the AMI. However, we may choose not to participate in a pad connection opportunity presented by a customer if we believe that the project 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 margin, or, in some cases, we may release the relevant acreage dedication from the AMI.

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, quarterly or annual minimum revenue stream. As of December 31, 2017, we had remaining MVCs totaling 2.6 Tcfe. Our MVCs, had a weighted-average remaining life of 7.4 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1.0 Bcfe/d through 2022. 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. As a result of this mechanism, the weighted-average remaining period for which our MVCs apply is less than the weighted-average of the original stated contract terms of our MVCs.

For additional information on our MVCs, see the "Critical Accounting Estimates" section in MD&A and Notes 2 and 8 to the consolidated financial statements.

Utica Shale

Summit Utica. In March 2016, we acquired certain natural gas gathering pipeline and dehydration assets in the Utica Shale from a subsidiary of Summit Investments. We refer to these assets as the Summit Utica system. The Summit Utica system is a natural gas gathering system located in the Appalachian Basin 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 system, which includes XTO and Ascent as its key customers, is currently in service and under development and had throughput capacity of 600 MMcf/d as of December 31, 2017. The Summit Utica system gathers and delivers natural gas, primarily under long-term, fee-based gathering agreements which include acreage dedications. The system interconnects with Energy Transfer Partners, L.P.’s ("Energy Transfer Partners") Utica Ohio River 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.

Ohio Gathering

Ohio Gathering. In March 2016, we acquired substantially all of a 40% ownership interest in Ohio Gathering from a subsidiary of Summit Investments. Non-affiliated owners have a 60% ownership interest in 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 natural gas, condensate and NGLs production from the Utica and Point Pleasant shale formations across Harrison, Guernsey, Belmont, Noble and Monroe counties in

Table of Contents

southeastern Ohio. Gulfport and Ascent are Ohio Gathering's key customers. Condensate and liquids-rich gas production is gathered, compressed, dehydrated and delivered to the Cadiz and Seneca processing complexes, which are owned by a joint venture between MPLX LP (“MPLX”) and The Energy and Minerals Group (“EMG”). Dry gas production is gathered, compressed, dehydrated and delivered to a downstream interconnect with Texas Eastern Transmission, or TETCO, and another third-party pipeline, which provides access to other third-party pipelines serving the northeast and mid-west markets. Substantially all gathering services on the Ohio Gathering system are provided pursuant to long-term, fee-based gathering agreements.

The condensate stabilization facility commenced operations in February 2015. Condensate stabilization allows for producers to capture the NGLs that would otherwise flash from condensate in atmospheric conditions. As one of the largest stabilization facilities in the Utica Shale, this facility serves as the origination point for MPLX’s Cornerstone Pipeline which delivers condensate to Marathon Petroleum’s refinery in Canton, Ohio.

For additional information, see Note 7 to the consolidated financial statements.

Williston Basin

The following table provides operating information regarding our Williston Basin reportable segment as of December 31, 2017.

	Aggregate throughput capacity - liquids (Mbbl/d)	Aggregate throughput capacity - natural gas (MMcf/d)	Average daily MVCs through 2022 (MMcfe/d) (1)	Remaining MVCs (Bcfe) (1)	Weighted-average remaining contract life (Years) (1)(2)
Williston Basin	300	46	99	181	4.0

(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 acres in the aggregate.

Polar and Divide. In May 2015, we acquired certain crude oil and produced water gathering systems in the Williston Basin from a subsidiary of Summit Investments. Subsequent to this acquisition, we have developed and commissioned additional gathering and transmission pipelines. In connection with the 2016 Drop Down, we also acquired crude oil and produced water gathering pipelines. We refer to these assets, which commenced operations in the second quarter of 2013, as the Polar and Divide system. 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 the Bakken and Three Forks shale formations.

The Polar and Divide system is underpinned by two long-term, fee-based gathering agreements with Whiting and SM Energy. In addition to Whiting and SM Energy, the Polar and Divide system is also supported by other long-term, fee-based gathering agreements.

Crude oil that is gathered by the Polar and Divide system is primarily delivered to The Dakota Access Pipeline and produced water is delivered to third-party disposal facilities. The Polar and Divide system also has interconnects into Crestwood Equity Partners LP's COLT Hub rail facility in Epping, North Dakota, Enbridge’s North Dakota Pipeline System in Williams County, North Dakota and Global Partners LP's Basin Transload rail terminal in Columbus, North Dakota. The Polar and Divide system currently provides crude oil and produced water midstream services for the Williston Basin reportable segment.

Tioga Midstream. In March 2016, we acquired certain associated natural gas, crude oil and produced water gathering systems in the Williston Basin from a subsidiary of Summit Investments. We refer to these assets, which commenced natural gas operations in the fourth quarter of 2014 and liquids operations in the third quarter of 2015, as the Tioga Midstream system. The Tioga Midstream system is located in Williams County, North Dakota. All gathering services on the Tioga Midstream system are 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

Table of Contents

gathering agreements include an annual rate redetermination mechanism which effectively 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 Hess Midstream Partners LP. The Tioga Midstream system currently provides associated natural gas, crude oil and produced water midstream services for the Williston Basin reportable segment.

Bison Midstream. In June 2013, we acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Williston Basin from a subsidiary of Summit Investments. We refer to these assets as the Bison Midstream system. 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. These formations are primarily targeted for crude oil production. As such, producer drilling and completion activity decisions, and consequently Bison Midstream's volume throughput, are based largely on the prevailing price of crude oil.

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 MVCs from its key customers. In addition to its percent-of-proceeds gathering agreement with Oasis and its fee-based gathering agreement with a large U.S. independent crude oil and natural gas company, the Bison Midstream system is also supported by other fee-based gathering agreements. 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.

Piceance/DJ Basins

The following table provides operating information regarding our Piceance/DJ Basins reportable segment as of December 31, 2017.

	Aggregate throughput capacity (MMcf/d)	Average daily MVCs through 2022 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Piceance/DJ Basins	1,282	561	1,345	7.5

_____

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

AMIs for the Piceance/DJ Basins reportable segment total approximately 840,000 acres in the aggregate.

Grand River. In 2011, we acquired certain natural gas gathering pipeline, dehydration and compression assets in the Piceance Basin from a third party. We refer to these assets as the Grand River system. The Grand River system is primarily located in Garfield County, one of the largest natural gas producing counties in Colorado. It gathers natural

gas produced from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin.

In March 2014, we acquired certain natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin from a subsidiary of Summit Investments. We refer to these assets as the Red Rock Gathering system, or Red Rock Gathering. Red Rock Gathering gathers and processes natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located in western Colorado and eastern Utah. Red Rock Gathering is primarily located in Garfield, Rio Blanco and Mesa counties in Colorado and Uintah and Grand counties in Utah. The Grand River and Red Rock Gathering systems have been connected and are managed as a single system, which we collectively refer to as the Grand River system.

Table of Contents

The Grand River system is primarily a low-pressure gathering system that was originally designed to gather natural gas produced from directional wells targeting the liquids-rich Mesaverde formation. The Mesaverde is a shallow, tight sands geologic formation that producers have targeted with directional drilling for several decades. We also gather 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) Enterprise Product Partners' 1.8 Bcf/d processing facility located in Meeker, Colorado, (ii) Williams Partners L.P.'s Northwest Pipeline and (iii) Kinder Morgan, Inc.'s TransColorado Pipeline system. Processed NGLs from Grand River are injected into Enterprise's Mid-America Pipeline system or delivered to local markets. In addition, certain of our gathering agreements with our Grand River customers 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 has multiple long-term, fee-based gathering agreements with Caerus as well as fee-based agreements with Terra, Black Hills Exploration and Production, Inc. ("Black Hills") and Ursa Resources Group II LLC (“Ursa”) which include long-term acreage dedications and MVCs. Certain of the Grand River system's other gathering and processing agreements include MVCs and AMIs.

In 2015, we executed an expansion agreement with a wholly owned subsidiary of Ursa to provide additional throughput capacity in exchange for new MVCs. In connection with the Black Hills gathering agreement, in March 2014 we commissioned a 20 MMcf/d cryogenic processing plant and related gas gathering infrastructure in the DeBeque, Colorado area to support Black Hills' development of its acreage targeting the liquids-rich Mancos and Niobrara formations. In connection with the Terra gathering agreement, we agreed to expand our gathering and compression services by constructing gas gathering infrastructure in the Rifle, Colorado area.

We anticipate that the majority of our near-term throughput on the Grand River system will continue to originate from the Mesaverde formation. We expect to continue to pursue additional volumes on the low-pressure system to more fully utilize the system's existing throughput capacity. In addition, we believe that the Grand River system is optimally located for expansion to gather future production from the Mancos and Niobrara shale formations. The Grand River system currently provides midstream services for the Piceance/DJ Basins reportable segment.

Niobrara G&P. In March 2016, we acquired certain associated natural gas gathering pipeline, compression and processing assets in the DJ Basin from a subsidiary of Summit Investments. We refer to these assets as the Niobrara G&P system. The system, which is located in Weld County, Colorado, comprises a low-pressure and high-pressure associated natural gas gathering pipeline and cryogenic natural gas processing plant with processing capacity of 20 MMcf/d pursuant to a long-term, fee-based gathering and processing agreement with Fifth Creek and a large U.S. independent crude oil and natural gas company. In December 2017, Fifth Creek announced a merger with Bill Barrett which is expected to close in the first quarter of 2018. In November 2017, we announced the expansion of our existing 20 MMcf/d gathering and processing complex with the addition of a new 60 MMcf/d processing plant. We expect the new 60 MMcf/d processing plant to become operational in the fourth quarter of 2018. 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 Piceance/DJ Basins reportable segment.

Barnett Shale

The following table provides operating information regarding our Barnett Shale reportable segment as of December 31, 2017.

	Throughput capacity (MMcf/d)	Average daily MVCs through 2022 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Barnett Shale	480	2	3	0.8

(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 acres.

Table of Contents

DFW Midstream. In 2009 and 2014, we acquired certain natural gas gathering pipeline and compression assets in the Barnett Shale from third parties. We refer to these assets as the DFW Midstream system. The DFW Midstream system is primarily located in southeastern Tarrant County, in north-central Texas. As the largest natural gas-producing county in 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. Based on peak month average daily production rates sourced from the Railroad Commission of Texas as of December 2017, this area contains the most prolific wells in the Barnett Shale. 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 includes 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. 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 is underpinned by a long-term, fee-based gathering agreement with Total and by other long-term, fee-based gathering agreements. The DFW Midstream system is designed to benefit from incremental volumes arising from high-density, infill drilling on existing pad sites that are already connected to the gathering system and, as such, would not require significant additional capital expenditures. Development of the DFW Midstream system has enabled our customers to efficiently produce natural gas by utilizing horizontal drilling techniques from pad sites already connected in our AMIs. Given the urban nature of southeastern Tarrant County, we expect that the majority of future natural gas drilling in this area will occur from existing pad site locations. 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, 2017.

	Throughput capacity (MMcf/d)
Marcellus Shale (1)	1,050

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

Mountaineer Midstream. In June 2013, we acquired certain high-pressure natural gas gathering pipelines and compression assets located in the liquids-rich window of the Marcellus Shale Play from an affiliate of MarkWest Energy Partners, L.P. (“MarkWest,” which was acquired by MPLX). We refer to these assets as the Mountaineer Midstream system. This system, which operates in the Appalachian Basin, benefits from its location in Doddridge and Harrison counties in West Virginia where it gathers natural gas under a long-term, fee-based contract with Antero. The Mountaineer Midstream system consists of high-pressure natural gas gathering pipelines and two compressor stations. This liquids-rich natural gas gathering and compression system serves as a critical inlet to MPLX's Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia, which provides

downstream access to Midwest, mid-Atlantic and northeast regions of the United States.

In November 2013, we amended our original fee-based natural gas gathering agreement with Antero whereby we agreed to construct approximately nine miles of high-pressure pipeline on the Mountaineer Midstream system (the "Zinnia Loop"). The Zinnia Loop, which was commissioned in 2014, is underpinned by a minimum revenue commitment from Antero and increased throughput capacity to 1,050 MMcf/d to support Antero's drilling activities. The Mountaineer Midstream system currently provides midstream services for the Marcellus Shale reportable segment.

Table of Contents

Delaware Basin

Summit Permian. In July 2017, we executed an agreement with XTO to develop, own and operate a new associated natural gas gathering and processing system servicing acreage located in the northern Delaware Basin in Eddy and Lea counties in New Mexico. We are in the process of constructing a gathering and processing system with high and low pressure gathering and discharge pipelines, two compressor stations and a cryogenic processing plant with 60 MMcf/d of processing capacity. Our processing complex will have the ability to be expanded to over 600 MMcf/d of processing capacity, as warranted, to meet customer needs. We expect to process production from XTO and other nearby producers. The initial phase of the project is expected to be operational on or before June 1, 2018.

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 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. 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

Table of Contents

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

Table of Contents

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;
- 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

Table of Contents

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 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

Table of Contents

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.

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.

Table of Contents

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 Clean Water Act 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 Clean Water Act 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 and are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on oil and/or natural gas drilling activities. The EPA has also moved forward with various related 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. We do not believe these new regulations will have a direct effect on our operations, but because natural gas and/or crude oil production using hydraulic fracturing is growing rapidly in the United States, if new or more stringent federal, state or local legal restrictions relating to such 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.

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

Table of Contents

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 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, 2017, Summit Investments employed 347 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

Table of Contents

after the date they are filed with, or furnished to, the SEC. The filings are also available at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available through the SEC's website, www.sec.gov. Our press releases and recent investor presentations are also available on our website.

Item 1A. Risk Factors.

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

- Risks Related to our Business

- Risks Inherent in an Investment in Us

- Tax Risks

Risks Related to Our Business

Our principal business strategy is to increase the amount of cash distributions we make to our unitholders over time. 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. 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;

Table of Contents

- our debt service requirements and other liabilities, including the Deferred Purchase Price Obligation;
- fluctuations in our working capital needs;
- our ability to borrow funds and access 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 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.

Table of Contents

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 five unconventional resource basins: the Appalachian Basin, the Williston Basin, the Fort Worth Basin, the Piceance Basin, and the DJ Basin. Due to our limited industry and geographic diversity, adverse developments in the natural gas and crude oil industries or in our existing areas of operation could have a significantly greater impact 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.

Table of Contents

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 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;
- 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.

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.

Table of Contents

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.

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

Table of Contents

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 capital 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:

- severe weather;
- 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;

Table of Contents

- 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 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

Table of Contents

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.

Substantially 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.

Table of Contents

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. The construction of additions or modifications to our existing systems and the construction of new midstream assets 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. 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 we would be required to spend 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) 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. As such, if we are unable to raise expansion capital, we may lose the opportunity to make acquisitions 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

Table of Contents

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 0.50% and 0.75% to a range between 1.25% and 1.50% in December 2017. 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, 2017, we had $1.06 billion of indebtedness outstanding and the unused portion of our $1.25 billion Revolving Credit Facility totaled $989.0 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, 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.

Table of Contents

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 Revolving Credit Facility or Senior Notes indentures could result in a default or an event of default that could enable our lenders 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, 2017, we derived 14% 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 system 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

Table of Contents

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 2014, the North Dakota Industrial Commission ("NDIC") began to oversee the integrity and location of underground gathering pipelines that are not monitored by other state or federal agencies. In 2016, the NDIC 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. 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, extends certain safety-related reporting requirements to hazardous liquid gathering lines and requires 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 April 2017, 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. 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, and are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. EPA regulations require, among other matters, green completions of hydraulically-fractured wells. The requirement to conduct green completions, and the corresponding notification and reporting requirements, 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. EPA announced in April 2017 that it would review these regulations and has proposed to stay their requirements. However,

Table of Contents

the regulations currently remain in effect. If new or more stringent federal, state or local legal restrictions relating to such 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, which could adversely affect our results of operations and financial condition.

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. 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 $1,238,271 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 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 $1,098,190 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.

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

Table of Contents

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

Table of Contents

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 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 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. 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. EPA is currently reconsidering NSPS OOOOa and has proposed to stay its requirements. However, the rule 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.

Independent of Congress, the EPA has begun to adopt 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.

Table of Contents

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 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.

Table of Contents

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.

Civil protests and resulting regulatory uncertainty may prevent or delay construction and the realization of revenues associated with pipeline projects.

Civil protests regarding environmental and social issues, including those related to construction of infrastructure associated with fossil fuels, may prevent or delay the construction of such infrastructure and realization of associated revenues. Such protests could delay construction or operation of our gathering pipelines that are protested, if any, or that connect to protested infrastructure projects and, in turn, receipt of revenues associated with our 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 confidential or proprietary information as well as disrupt our operations 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.

Table of Contents

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 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 or sell midstream assets 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.

Table of Contents

- 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.
- 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.

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.

Table of Contents

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 73,085,996 common units outstanding at December 31, 2017, Summit Investments beneficially owned 25,854,581 common units. As of December 31, 2017, a subsidiary of Energy Capital Partners directly owned 5,915,827 common units. 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;
- 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.

Table of Contents

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;
- 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;
- 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.

Table of Contents

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

Table of Contents

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 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, our 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, 2017, Summit Investments beneficially owned 25,854,581 common units out of 73,085,996 outstanding common units. Additionally, a subsidiary of Energy Capital Partners directly owned 5,915,827 common units as of December 31, 2017.

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 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.

Table of Contents

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.

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 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, 2017, Summit Investments beneficially owned

25,854,581 common units out of 73,085,996 outstanding common units, representing a voting block sufficient to prevent the other limited partners from removing our General Partner.

Table of Contents

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.

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, 2017, Summit Investments beneficially owned 25,854,581 common units out of 73,085,996 outstanding common units. Additionally, a subsidiary of Energy Capital Partners directly owned 5,915,827 common

Table of Contents

units as of December 31, 2017. 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, 2017, Summit Investments beneficially owned 25,854,581 common units out of 73,085,996 outstanding common units. Additionally, a subsidiary of Energy Capital Partners directly owned 5,915,827 common units as of December 31, 2017. As such, our General Partner and its affiliates controlled a total of 31,770,408 common units, or 43.5% of our common units outstanding as of December 31, 2017.

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

Table of Contents

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 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

Table of Contents

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.

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.

Table of Contents

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 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.

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

Table of Contents

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. 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 recently enacted tax reform law, 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.

Table of Contents

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 the recently enacted tax reform law known as the Tax Cuts and Jobs Act, it is uncertain whether a guaranteed payment for the use of capital may 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

Table of Contents

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.

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.

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

Table of Contents

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.

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;
- 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/DJ Basins 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 Piceance/DJ Basins 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.

In addition, Summit Permian is an associated natural gas gathering and processing system under development in the northern Delaware Basin in southeastern New Mexico. 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

Table of Contents

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 operating 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.

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 proceedings contemplated to be brought against us, under the various environmental protection statutes to which we are subject, except as noted below.

In 2015 and 2016, the U.S. Department of Justice 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.

Table of Contents

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 16, 2018, there were approximately 7,846 common unitholders, including beneficial owners of common units held in street name. The following table shows the common unit price range, as reported by the NYSE, and the cash distribution paid per common unit for the periods indicated.

	Common unit price range		Cash distribution paid per common unit (1)
	High	Low	
4th Quarter 2017	$21.78	$18.30	$ 0.575
3rd Quarter 2017	$24.75	$19.15	$ 0.575
2nd Quarter 2017	$24.50	$21.10	$ 0.575
1st Quarter 2017	$26.50	$22.00	$ 0.575
4th Quarter 2016	$25.50	$19.95	$ 0.575
3rd Quarter 2016	$25.10	$20.88	$ 0.575
2nd Quarter 2016	$23.85	$15.05	$ 0.575
1st Quarter 2016	$19.65	$11.06	$ 0.575

(1) Represents historical distributions based on the quarter in which they were paid.

On January 25, 2018, the Board of Directors of our General Partner declared a distribution of $0.575 per unit for the quarterly period ended December 31, 2017. The distribution, which totaled $45.1 million, was paid on February 14, 2018, to unitholders of record at the close of business on February 7, 2018.

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. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the minimum quarterly distribution stated in our Partnership Agreement. 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.

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. For additional information, see Note 11 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 the minimum quarterly distribution or any other 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:

Table of Contents

- 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 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.
- 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, 2017, Summit Investments, which is the ultimate owner of our General Partner, beneficially owned 25,854,581 common units. In addition, a subsidiary of Energy Capital Partners owned 5,915,827 common units as of December 31, 2017.
- 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.

Our Minimum Quarterly Distribution

Our Partnership Agreement has established an MQD of $0.40 per unit per quarter, or $1.60 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter. Based on all of the units outstanding as of December 31, 2017, our aggregate quarterly MQD is $29.8 million and our aggregate annual MQD is $119.3 million.

Preferred Unit Distributions

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.

Distributions on the Series A Preferred Units will be cumulative and compounding and will be 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 will be 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

Table of Contents

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%. A pro-rated initial distribution on the Series A Preferred Units was paid on December 15, 2017 in an amount equal to approximately $7.9167 per Series A Preferred Unit, which totaled $2.4 million. See Note 11 for additional details.

Stock Performance Table

The following graph compares the cumulative total unitholder return on our common units since the IPO to the cumulative total return of the S&P 500 Stock Index and the Alerian MLP Index ("AMZX") by assuming $100 was invested in each investment option as of September 28, 2012, the date of the IPO. The Alerian MLP Index is a composite of the 39 most prominent 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 ended December 31, 2017.

Sponsor Purchases of Equity Securities

Our Sponsor made no repurchases of our common units during the quarter ended December 31, 2017.

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, 2017, 2016, 2015, 2014 and 2013 have been derived from the consolidated financial statements of SMLP.

Table of Contents

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; (iv) Mountaineer Midstream since June 2013; (v) Bison Midstream, Polar and Divide and Meadowlark Midstream since February 2013; and (vi) Red Rock Gathering, DFW Midstream and Grand River 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 consideration paid and recognized for a contributed subsidiary is recognized as an addition to partners' capital, while the excess of consideration 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.

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

	December 31,				
	2017	2016	2015	2014	2013
	(In thousands, except per-unit amounts)				
Balance sheet data:					
Total assets	$2,894,793	$3,115,179	$3,164,672	$3,242,462	$2,282,046
Total long-term debt	1,051,192	1,240,301	1,267,270	1,232,207	772,140
Deferred Purchase Price Obligation	362,959	563,281	—	—	—
Partners' capital	1,389,669	1,169,673	1,747,299	1,830,678	1,395,806
Other data:					
Market price per common unit	$20.50	$25.15	$18.73	$38.00	$36.65

Table of Contents

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,				
	2017	2016	2015	2014	2013
	(In thousands, except per-unit amounts)				
Statements of operations data:					
Total revenues	$488,741	$402,362	$400,557	$387,169	$326,160
Total costs and expenses (1)	510,577	290,582	557,735	369,574	257,114
Interest expense	68,131	63,810	59,092	48,586	21,314
Early extinguishment of debt	22,039	—	—	—	—
Deferred Purchase Price Obligation	(200,322)	55,854	—	—	—
Loss from equity method investees (2)	(2,223)	(30,344)	(6,563)	(16,712)	—
Net income (loss)	86,050	(38,187)	(222,228)	(47,368)	47,008
Earnings (loss) per limited partner unit:					
Common unit - basic	$0.99	$(0.71)	$(3.20)	$(0.49)	$0.86
Common unit - diluted	0.98	(0.71)	(3.20)	(0.49)	0.86
Subordinated unit - basic and diluted (3)			(2.88)	(0.44)	0.79
Statements of cash flows data:					
Capital expenditures	$124,215	$142,719	$272,225	$343,380	$249,626
Acquisition capital expenditures (4)	—	866,858	288,618	315,872	458,914
Other financial data:					
Distributions declared per unit (5)	$2.300	$2.300	$2.270	$2.040	$1.725

(1) Includes (i) long-lived asset impairments of $101.9 million and contract intangible asset impairments of $85.2 million in 2017, (ii) goodwill impairments of $248.9 million and environmental remediation expenses of $21.8 million in 2015 and (iii) goodwill impairments of $54.2 million in 2014. See Notes 4, 5, 6 and 15 to the consolidated financial statements.

(2) Includes our 40% share, or $1.4 million impairment loss recognized by Ohio Gathering in December 2017.

(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 11 and 16 to the consolidated financial statements).

(5) Represents distributions declared in a given period. For example, for the year ended December 31, 2017, represents the distributions declared in February 2017, in May 2017, in August 2017 and in November 2017.

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

Table of Contents

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

- Summit Permian, an associated natural gas gathering and processing system under development in the northern Delaware Basin in southeastern New Mexico.

For additional information on our organization and systems, see Notes 1 and 3 to the consolidated financial statements.

Table of Contents

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 substantial majority of the volumes that we gather, treat and/or process have a fixed-fee rate structure thereby enhancing 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 system customers and (iv) the sale of condensate we retain from our gathering services at Grand River. These additional activities, which expose us to direct commodity price risk, accounted for less than 14% of total revenues during the year ended December 31, 2017. We expect our natural gas and crude oil marketing services to increase in future periods resulting in a higher exposure to direct commodity price risk.

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 recognize a minimum amount of revenue.

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, 2017, 2016 and 2015" section herein.

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Net income (loss)	$86,050	$(38,187)	$(222,228)
Reportable segment adjusted EBITDA			
Utica Shale	$34,011	$21,035	$2,206
Ohio Gathering	41,246	45,602	33,667
Williston Basin	66,413	79,475	34,008
Piceance/DJ Basins	117,737	109,241	110,222
Barnett Shale	46,232	54,634	59,526
Marcellus Shale	23,888	19,203	23,214
Net cash provided by operating activities	$237,832	$230,495	$191,375
Acquisitions of gathering systems (1)	—	866,858	288,618
Capital expenditures (2)	124,215	142,719	272,225
Contributions to equity method investees	25,513	31,582	86,200
Distributions to unitholders	$181,478	$167,504	$152,074
Issuance of senior notes	500,000	—	—
Tender and redemption of senior notes	(300,000)	—	—
Net (repayments) borrowings under Revolving Credit			
Facility	(387,000)	316,000	216,000
Proceeds from underwritten issuance of common units,	—	125,233	221,977

net of costs (3)			
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 16 to the consolidated financial statements).

(2) See "Liquidity and Capital Resources" herein and Note 3 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.

Table of Contents

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 (see Note 8 to the consolidated financial statements).
- In November 2017, we issued 300,000 Series A Preferred Units representing limited partner interests in the Partnership at a price of $1,000 per unit. We used the net proceeds of $293.2 million to repay outstanding borrowings under our Revolving Credit Facility.
- In 2017, we updated the Deferred Purchase Price Obligation based on management's estimate of forecasted Business Adjusted EBITDA (see Note 16 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, 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 intangible and long-lived assets relating to the Bison Midstream system in the Williston Basin were not fully recoverable and we recorded an impairment charge of $187.1 million.

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 11 and 16 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.

Year ended December 31, 2015. The following items are reflected in our financial results:

- In May 2015, we acquired Polar and Divide from a subsidiary of Summit Investments. We funded the drop down with the issuance of common units, borrowings under our Revolving Credit Facility and a General Partner

contribution (see Notes 11 and 16 to the consolidated financial statements).

- In May 2015, we completed an underwritten public offering of 7,475,000 common units at a price of $30.75 per unit and used a portion of the net proceeds to partially fund the Polar and Divide Drop Down. Following the offering, our General Partner made a capital contribution to us to maintain its approximate 2% general partner interest.

Table of Contents

- In September 2015, we recognized $34.4 million of gathering services and related fees revenue that had been previously deferred in connection with an MVC arrangement with a certain Piceance/DJ Basins customer, which was determined to no longer be recoverable by the customer. We include the effect of adjustments related to MVC shortfall payments in our definition of segment adjusted EBITDA. As such, Piceance/DJ Basins 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 September and December 2015, we recognized additional accruals for environmental remediation expenses totaling $21.8 million associated with the rupture of a produced water gathering pipeline in the Williston Basin reportable segment (see Note 15 to the consolidated financial statements).
- After a slight pause mid-year 2015, crude oil and NGL prices continued to decline in response to the global supply surplus. As a result, several of the producers in our areas of operations announced plans to cancel, delay and/or reduce drilling plans, which in turn negatively impacted the margins that we earn, slowing the growth in net income. In addition to impacting the margins that we earn and net income, the goodwill that we had previously recognized in connection with our acquisitions of Polar and Divide and Grand River was determined to be fully impaired, resulting in a write-off of $248.9 million.

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 2017 relative to 2016. The average daily Henry Hub Natural Gas Spot Price was $2.99 per one million British Thermal Units ("MMBtu") during 2017, compared with $2.52 per MMBtu during 2016. Henry Hub closed at $3.69 per MMBtu on December 29, 2017. 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 2016 and 2017, with the average daily West Texas Intermediate ("WTI") crude oil spot price increasing from an average $43.29 per barrel during 2016 to an average of $50.80 per barrel during 2017, representing a 17% increase. WTI closed at $60.46 per barrel on December 29, 2017. In response to the increase in crude oil prices, the number of active crude oil drilling rigs in the continental United States increased from 525 in December 2016 to 747 in December 2017, according to Baker Hughes. Over the next several years, we expect that crude oil prices will rebound sufficiently to support continued drilling and increasing production in the Bakken Shale,

Eagle Ford Shale, Permian Basin and Niobrara Shale.

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

Table of Contents

the development of these unconventional resources, including the Piceance, Barnett, Bakken, Marcellus, Utica and Delaware Basin shale plays in which we operate, and we believe that these long-term capital investments will support sustained drilling activity in unconventional shale plays.

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 downward revision in the estimated undiscounted value of the Deferred Payment as of December 31, 2017 relative to our estimate as of December 31, 2016.

Capital markets availability and cost of capital. Credit markets improved substantially throughout 2017, as borrowing costs were lower relative to the levels generally experienced during the 2008 global financial crisis for virtually all energy industry-related borrowers. The credit market trends in the crude oil and natural gas industry during 2016 were unique relative to the broader economy. While borrowing costs came down for the oil and natural gas industry as a whole, the Federal Reserve raised its benchmark federal-funds rate from 0.50% and 0.75% in December 2016 to a range between 1.25% and 1.50% in December 2017. The Federal Reserve also announced its intent to continue to raise interest rates gradually 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. 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 six reportable segments. We evaluate our business operations each reporting period to determine whether any of our gathering system 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 second quarter of 2017, we determined that both the Summit Utica natural gas gathering system and the Ohio Gathering natural gas gathering system, each previously reported within the Utica Shale reportable segment, were and are expected to continue to be significant operating segments. As such, we modified our current segments in the second quarter of 2017 such that the Utica Shale reportable segment includes the Summit Utica gathering system and the Ohio

Gathering reportable segment includes our ownership interest in OGC and OCC. For the year ended December 31, 2017, we have disclosed the required segment information for Summit Utica and Ohio Gathering 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;

Table of Contents

- the Williston Basin, which is served by Polar and Divide, Tioga Midstream and Bison Midstream;
- the Piceance/DJ Basins, which is served by Grand River and Niobrara G&P;
- 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. Capital expenditures attributable to the ongoing development of Summit Permian is included in Corporate and Other. 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 3 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, 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 substantial majority of our gathering and processing agreements are fee-based, which limits our direct commodity price exposure. 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.

Many 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

Table of Contents

amount, over certain periods during the term of the MVC. These MVCs support our 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 used as a supplemental financial measure 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, treating and processing services that we provide to our natural gas and crude oil producer 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 system 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 our Bison Midstream and Grand River 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 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 and (ii) the purchase of natural gas and NGLs associated with marketing activity surrounding our natural gas-related operations.

Table of Contents

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.

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.

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, our Senior Notes and debt that was previously incurred by SMP Holdings and allocated to SMLP in connection with the 2016 Drop Down.

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.

Table of Contents

Consolidated Overview for the Years Ended December 31, 2017, 2016 and 2015

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

	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$394,427	$345,961	$337,819	14%	2%
Natural gas, NGLs and condensate sales	68,459	35,833	42,079	91%	(15%)
Other revenues	25,855	20,568	20,659	26%	—%
Total revenues	488,741	402,362	400,557	21%	—%
Costs and expenses:					
Cost of natural gas and NGLs	57,237	27,421	31,398	109%	(13%)
Operation and maintenance	93,882	95,334	94,986	(2%)	—%
General and administrative	54,681	52,410	45,108	4%	16%
Depreciation and amortization	115,475	112,239	105,117	3%	7%
Transaction costs	73	1,321	1,342	(94%)	(2%)
Environmental remediation	—	—	21,800	*	*
Loss (gain) on asset sales, net	527	93	(172)	*	*
Long-lived asset impairment	188,702	1,764	9,305	*	*
Goodwill impairment	—	—	248,851	*	*
Total costs and expenses	510,577	290,582	557,735	76%	(48%)
Other income	298	116	2	*	*
Interest expense	(68,131)	(63,810)	(59,092)	7%	8%
Early extinguishment of debt	(22,039)	—	—	*	*
Deferred Purchase Price Obligation	200,322	(55,854)	—	*	*
Income (loss) before income taxes and loss from equity method investees	88,614	(7,768)	(216,268)	*	*
Income tax (expense) benefit	(341)	(75)	603	*	*
Loss from equity method investees	(2,223)	(30,344)	(6,563)	93%	*
Net income (loss)	$86,050	$(38,187)	$(222,228)	*	83%
Volume throughput (1):					
Aggregate average daily throughput - natural gas (MMcf/d)	1,748	1,528	1,499	14%	2%
Aggregate average daily throughput - liquids (Mbbl/d)	75.2	88.9	67.7	(15%)	31%

* Not considered meaningful

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

Volumes – Gas. Natural gas throughput volumes increased 220 MMcf/d during the year ended December 31, 2017, as compared to the prior year, primarily reflecting:

- 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.

Natural gas throughput volumes increased 29 MMcf/d during the year ended December 31, 2016, as compared to prior year, primarily reflected:

- a volume throughput increase of 149 MMcf/d for the Utica Shale segment.
- a volume throughput decrease of 63 MMcf/d for the Marcellus Shale segment.
- a volume throughput decrease of 33 MMcf/d for the Barnett Shale segment.
- a volume throughput decrease of 23 MMcf/d for the Piceance/DJ Basins segment.

Table of Contents

For additional information on volumes, see the "Segment Overview for the Years Ended December 31, 2017, 2016 and 2015" section herein.

Volumes – Liquids. 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.

Crude oil and produced water throughput volumes increased 21.2 Mbbl/d during the year ended December 31, 2016, as compared to the prior year, primarily reflected the continued development of the Polar and Divide and Tioga Midstream systems, new pad site connections and producers' ongoing drilling activity, partially offset by the second quarter 2016 impact of certain customers shutting in existing production while completion activities occurred.

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

- 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 $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 and Piceance/DJ Basins 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.

Total revenues increased $1.8 million, during the year ended December 31, 2016, as compared to the prior year, primarily reflected:

- an $8.1 million increase in gathering services and related fees primarily as a result of increases for the Utica Shale and Williston Basin segments, partially offset by decreases for the Piceance/DJ Basins, Barnett Shale and Marcellus Shale segments.
- a $6.2 million decline in natural gas, NGLs and condensate sales due to decreases for the Williston Basin, Piceance/DJ Basins and Barnett Shale segments.

Gathering Services and Related Fees. Gathering services and related fees increased $48.5 million during the year ended December 31, 2017, as compared to the prior year, primarily reflecting:

- 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.

Table of Contents

Gathering services and related fees increased $8.1 million during the year ended December 31, 2016, as compared to the prior year, primarily reflected:

- an increase of $27.1 million for the Williston Basin segment primarily due to higher volume throughput on the Polar and Divide system as well as the growth of the Tioga Midstream system.
- an increase of $19.6 million for the Utica Shale segment due to the development of the Summit Utica system.
- a $27.9 million decrease in gathering services and related fees for the Piceance/DJ Basins segment primarily as a result of the 2015 recognition of $34.4 million of deferred revenue for the Grand River system.
- an $8.2 million decrease for the Barnett Shale segment primarily due to lower volume throughput on the DFW Midstream system.

Natural Gas, NGLs and Condensate Sales. 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 and crude oil marketing services provided for the Piceance/DJ Basins and Barnett Shale segments and the impact of higher comparative commodity pricing and throughput of NGLs on our Williston Basin and Piceance/DJ Basins segments.

Natural gas, NGLs and condensate sales decreased $6.2 million during the year ended December 31, 2016 primarily reflected the impact on pricing and throughput of lower commodity prices on our Williston Basin, Piceance/DJ Basins and Barnett Shale segments, which in turn impacted volume throughput as well as the associated sales, during the first half of 2016.

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

- 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 $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.

Total costs and expenses decreased $267.2 million, or 48%, for the year ended December 31, 2016, as compared to the prior year, primarily reflected:

- the 2015 recognition of $248.9 million of goodwill impairments for the Williston Basin and Piceance/DJ Basins segments.
- the 2015 recognition of a $21.8 million environmental remediation accrual for assets contributed to Polar and Divide in connection with the 2016 Drop Down.
- a $7.5 million decrease in long-lived asset impairments, primarily for the Williston Basin segment.
- a $4.0 million decrease in cost of natural gas and NGLs for the Bison Midstream and Grand River systems primarily due the impact of declining commodity prices on their percent-of-proceeds and condensate sales activity during the first half of 2016.
- a $7.3 million increase in general and administrative expense primarily due to an increase in salaries, benefits and incentive compensation.
- a $7.1 million increase in depreciation and amortization for all segments.

Table of Contents

Cost of Natural Gas and NGLs. Cost of natural gas and NGLs increased $29.8 million during the year ended December 31, 2017, as compared to the prior period. The increase was attributable to 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/DJ Basins 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.

Cost of natural gas and NGLs decreased $4.0 million during the year ended December 31, 2016, as compared to the prior period, which largely reflected the impact on pricing and throughput of lower comparative commodity prices on our Williston Basin and Piceance/DJ Basins segments during the first half of 2016 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 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.

Operation and maintenance expense increased $0.3 million during the year ended December 31, 2016 primarily reflecting (i) overall increases for Utica Shale and Williston Basin segments, primarily as a result of the development of the Summit Utica, Tioga Midstream and Polar and Divide systems and (ii) an increase for the Marcellus Shale segment for expenses associated with repairs to rights-of-ways on the Mountaineer Midstream system. The impact of these items was partially offset by declines for the Piceance/DJ Basins and Barnett Shale segments.

General and Administrative. 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.

General and administrative expense increased $7.3 million during the year ended December 31, 2016 primarily reflecting an increase in expenses for salaries, benefits and incentive compensation. For additional information, see the "Corporate and Other Overview of the Years Ended December 31, 2017, 2016 and 2015" sections herein.

Depreciation and Amortization. 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. The increase in depreciation and amortization expense during 2016 was largely driven by an increase in assets placed into service.

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. Transaction costs recognized during the year ended December 31, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down. Transaction costs in 2015 also include financial and legal advisory expenses incurred by Summit Investments for third-party acquisitions that were allocated to us in connection with the 2016 Drop Down.

Interest Expense. 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.

The increase in interest expense during the year ended December 31, 2016 was primarily driven by (i) higher costs associated with increased borrowings on our Revolving Credit Facility and (ii) debt incurred by Summit Investments that was allocated to the Partnership in connection with the 2016 Drop Down. The Revolving Credit Facility borrowings incurred in March 2016 in connection with funding a portion of the 2016 Drop Down purchase price replaced the lower-rate Summit Investments' debt that had been allocated to us prior to our March 2016 closing of the 2016 Drop Down, resulting in an increase in interest expense.

Table of Contents

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. 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.

The Deferred Purchase Price Obligation recognized in 2016 relates to our March 2016 issuance of the deferred payment in connection with the 2016 Drop Down (see Notes 2 and 16 to the consolidated financial statements).

For additional information, see the "Segment Overview for the Years Ended December 31, 2017, 2016 and 2015" and "Corporate and Other Overview for the Years Ended December 31, 2017, 2016 and 2015" sections herein.

Segment Overview for the Years Ended December 31, 2017, 2016 and 2015

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	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Average daily throughput (MMcf/d)	365	186	37	96%	*

* Not considered meaningful

Volume throughput increased during 2017 and 2016 due to the ongoing development of the Summit Utica system and completion of new wells during the second half of 2016 and 2017. In late March 2017, we commissioned the TPL-7 connector project which contributed to increased volumes compared to the prior period.

Table of Contents

Financial data for our Utica Shale reportable segment follows.

	Utica Shale				
	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$38,907	$24,263	$4,700	60%	*
Total revenues	38,907	24,263	4,700	60%	*
Costs and expenses:					
Operation and maintenance	4,487	2,280	1,017	97%	124%
General and administrative	409	948	1,477	(57%)	(36%)
Depreciation and amortization	7,009	4,331	1,417	62%	*
Loss (gain) on asset sales, net	542	(4)	—	*	*
Long-lived asset impairment	878	—	—	*	*
Total costs and expenses	13,325	7,555	3,911	76%	93%
Add:					
Depreciation and amortization	7,009	4,331	1,417		
Loss (gain) on asset sales, net	542	(4)	—		
Long-lived asset impairment	878	—	—		
Segment adjusted EBITDA	$34,011	$21,035	$2,206	62%	*

* Not considered meaningful

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.

Year ended December 31, 2016. Segment adjusted EBITDA increased $18.8 million during 2016 primarily reflecting:

- a $19.6 million increase in gathering services and related fees as a result of the growth and development of the Summit Utica system.

Other items to note:

- Depreciation and amortization increased over 2015 as a result of placing assets into service at the Summit Utica system.

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	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Average daily throughput (MMcf/d)	766	865	645	(11%)	34%

Table of Contents

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.

Volume throughput for the Ohio Gathering system increased during 2016, compared to the prior period, primarily as a result of increased drilling and completion activity.

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

	Ohio Gathering				
	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Proportional adjusted EBITDA for equity method investees	$41,246	$45,602	$33,667	(10%)	35%
Segment adjusted EBITDA	$41,246	$45,602	$33,667	(10%)	35%

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.

Year ended December 31, 2016. Segment adjusted EBITDA increased $11.9 million during 2016, compared to the prior period, primarily reflecting an increase in our proportional share of Ohio Gathering's adjusted EBITDA primarily due to growth and development in the first half of 2016. Volume growth decelerated for both OGC and OCC beginning in the third quarter of 2016, thereby slowing the year-over-year overall increase.

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	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Aggregate average daily throughput - natural gas (MMcf/d)	19	22	23	(14%)	(4%)

Aggregate average daily throughput -					
liquids (Mbbl/d)	75.2	88.9	67.7	(15%)	31%

Natural gas. Natural gas volume throughput decreased during 2017, compared to the prior period, largely reflecting natural production declines.

Natural gas volume throughput remained flat during 2016, compared to the prior period, largely reflecting the offsetting effects of the growth of the Tioga Midstream system throughout 2015 and into the first quarter of 2016 and lower volume throughput on the Bison Midstream system.

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

The increase in liquids volume throughput during 2016 reflects the completion of new wells across our gathering footprint and the connection of pad sites that had been previously using third-party trucks to gather crude oil and/or produced water. In addition, the impact of an early-January 2015 shut in of certain produced water and crude oil gathering pipelines constrained 2015 volume throughput.

Table of Contents

Financial data for our Williston Basin reportable segment follows.

	Williston Basin				
	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$120,717	$89,962	$62,899	34%	43%
Natural gas, NGLs and condensate sales	29,724	20,158	23,525	47%	(14%)
Other revenues	11,062	12,054	12,505	(8%)	(4%)
Total revenues	161,503	122,174	98,929	32%	23%
Costs and expenses:					
Cost of natural gas and NGLs	30,004	20,384	23,090	47%	(12%)
Operation and maintenance	25,058	28,430	26,586	(12%)	7%
General and administrative	2,335	2,576	5,400	(9%)	(52%)
Depreciation and amortization	33,772	33,676	31,376	—%	7%
Environmental remediation	—	—	21,800	*	*
(Gain) loss on asset sales, net	(22)	88	5	*	*
Long-lived asset impairment	187,127	569	7,554	*	*
Goodwill impairment	—	—	203,373	*	*
Total costs and expenses	278,274	85,723	319,184	*	(73%)
Add:					
Depreciation and amortization	33,772	33,676	31,376		
Adjustments related to MVC shortfall payments	(37,693)	8,691	11,870		
Unit-based compensation	—	—	85		
(Gain) loss on asset sales, net	(22)	88	5		
Long-lived asset impairment	187,127	569	7,554		
Goodwill impairment	—	—	203,373		
Segment adjusted EBITDA	$66,413	$79,475	$34,008	(16%)	134%

* Not considered meaningful

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 4 and 5 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 (see Note 8 to the consolidated financial statements).

Table of Contents

Year ended December 31, 2016. Segment adjusted EBITDA increased $45.5 million during 2016, compared to the prior period, primarily reflecting:

- a $23.9 million increase, after taking into account the adjustments related to MVC shortfall payments, in gathering services and related fees primarily due to (i) the development of the Polar and Divide and Tioga Midstream systems, (ii) higher gathering rates associated with a rate redetermination, which was in effect in the first and second quarters of 2016 and (iii) the prior-year impact of an early-January 2015 shut in of certain produced water and crude oil gathering pipelines.
- the 2015 recognition of an additional accrual of $21.8 million for environmental remediation costs associated with a produced water pipeline that became part of the Polar and Divide system in connection with the 2016 Drop Down.
- a $2.8 million decrease in general and administrative expense largely as a result of a higher allocation of certain corporate general and administrative expenses in 2015 for both the Polar and Divide and Tioga Midstream systems (see the "Corporate and Other Overview for the Years Ended December 31, 2017, 2016 and 2015—General and Administrative" section herein).

Other items to note:

- Depreciation and amortization increased during 2016 largely as a result of assets placed into service.
- In September 2015, we impaired certain property, plant and equipment balances associated with terminated projects. These impairments had no impact on segment adjusted EBITDA for the year ended December 31, 2015.
- In the fourth quarter of 2015, we recognized a goodwill impairment for the Polar and Divide system. This impairment had no impact on segment adjusted EBITDA for the year ended December 31, 2015.

Piceance/DJ Basins. The Grand River and Niobrara G&P systems provide midstream services for the Piceance/DJ Basins reportable segment. Volume throughput for our Piceance/DJ Basins reportable segment follows.

	Piceance/DJ Basins Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Aggregate average daily throughput (MMcf/d)	595	586	609	2%	(4%)

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 across our gathering footprint.

Volume throughput decreased during 2016, compared to the prior period, primarily as a result of the continued suspension of drilling activities by one of Grand River's key customers and the resulting natural declines from existing production. The impact of these decreases was partially offset by an increase in volume throughput by other producer customers.

Table of Contents

Financial data for our Piceance/DJ Basins reportable segment follows.

	Piceance/DJ Basins Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$145,752	$133,436	$161,291	9%	(17%)
Natural gas, NGLs and condensate sales	13,850	9,808	11,854	41%	(17%)
Other revenues	7,151	6,659	7,273	7%	(8%)
Total revenues	166,753	149,903	180,418	11%	(17%)
Costs and expenses:					
Cost of natural gas and NGLs	7,969	7,082	8,308	13%	(15%)
Operation and maintenance	35,144	33,524	36,674	5%	(9%)
General and administrative	2,835	3,027	3,624	(6%)	(16%)
Depreciation and amortization	48,925	49,140	47,433	—%	4%
Loss (gain) on asset sales, net	3	9	(190)	(67%)	*
Long-lived asset impairment	697	—	1,220	*	*
Goodwill impairment	—	—	45,478	*	*
Total costs and expenses	95,573	92,782	142,547	3%	(35%)
Add:					
Depreciation and amortization	48,925	49,140	47,433		
Adjustments related to MVC shortfall payments	(3,068)	2,971	(21,590)		
Loss (gain) on asset sales, net	3	9	(190)		
Long-lived asset impairment	697	—	1,220		
Goodwill impairment	—	—	45,478		
Segment adjusted EBITDA	$117,737	$109,241	$110,222	8%	(1%)

* Not considered meaningful

Year ended December 31, 2017. Segment adjusted EBITDA increased $8.5 million during 2017, compared to the prior period, primarily reflecting:

- $6.3 million increase, after taking into account the adjustments related to MVC shortfall payments, in gathering services and related fees primarily as a result of volume growth from ongoing drilling and completion activity in addition to a favorable rate mix with certain customers.

Year ended December 31, 2016. Segment adjusted EBITDA decreased $1.0 million during 2016, compared to the prior period, primarily reflecting:

- $3.3 million decrease in gathering services and related fees, after taking into account the adjustments related to MVC shortfall payments, primarily as a result of declining volumes from one of Grand River's key customers. This impact was partially offset by higher average volume throughput and rates due to a shift in customer mix.

- a $3.2 million decrease in operation and maintenance primarily due to lower general repairs and maintenance expenses.

Other items to note:

- Depreciation and amortization increased during 2016 largely as a result of an increase in contract amortization for one of Grand River's key customers.
- A portion of the change in adjustments for MVC shortfall payments is associated with our September 2015 decision to no longer defer $34.4 million of MVC shortfall payments from a certain Grand River customer. As a result, the decrease in gathering services and related fees compared with 2015 was offset by the change in adjustments related to MVC shortfall payments, with no impact on segment adjusted EBITDA (see Note 8 to the consolidated financial statements).

Table of Contents

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

Volume throughput for our Barnett Shale reportable segment follows.

	Barnett Shale Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Average daily throughput (MMcf/d)	267	319	352	(16%)	(9%)

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 activities throughout 2016.

Volume throughput declined during 2016, compared to the prior period, reflecting reduced drilling and completion activity, together with natural production declines, partially offset by the commissioning of an 11-well pad site in the second quarter of 2016 and the commissioning of 14 wells in December 2015 and January 2016.

Financial data for our Barnett Shale reportable segment follows.

	Barnett Shale Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$61,622	$72,234	$80,461	(15%)	(10%)
Natural gas, NGLs and condensate sales	1,946	5,867	6,700	(67%)	(12%)
Other revenues (1)	8,099	1,855	881	*	111%
Total revenues	71,667	79,956	88,042	(10%)	(9%)
Costs and expenses:					
Operation and maintenance	23,074	24,594	25,823	(6%)	(5%)
General and administrative	1,146	1,088	1,297	5%	(16%)
Depreciation and amortization	15,604	15,671	15,606	—%	—%
Loss on asset sales, net	4	—	13	*	*
Long-lived asset impairment	—	1,195	531	*	*
Total costs and expenses	39,828	42,548	43,270	(6%)	(2%)
Add:					
Depreciation and amortization	15,001	16,093	16,392		
Adjustments related to MVC shortfall	(612)	(62)	(2,182)		

payments					
Loss on asset sales, net	4	—	13		
Long-lived asset impairment	—	1,195	531		
Segment adjusted EBITDA	$46,232	$54,634	$59,526	(15%)	(8%)

*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, 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.

Table of Contents

Year ended December 31, 2016. Segment adjusted EBITDA decreased $4.9 million during 2016, compared to the prior period, primarily reflecting:

- a $6.1 million decrease, after taking into account the adjustments related to MVC shortfall payments, in gathering services and related fees largely as a result of reduced volume throughput.
- a $1.2 million decrease in operation and maintenance expense largely as a result of lower electricity expense. The decline in electricity expense was largely the result of (i) lower volumes not requiring as much compression as the prior-year period and (ii) the impact of lower natural gas prices on our cost of electricity.

Other items to note:

- Other revenues also reflect the effect of a $0.8 million increase in electricity expense reimbursements that we began passing through to certain customers beginning in the fourth quarter of 2016. Previously we had retained a portion of the gathered natural gas which was then sold to offset the electricity expense necessary to operate our electric-drive compression assets. Due to their pass-through nature, these revenues had no impact on segment adjusted EBITDA.

- The long-lived asset impairments in 2016 and 2015 reflect our decisions to impair certain property, plant and equipment balances associated with the decommissioning of certain assets. These impairments had no impact on segment adjusted EBITDA for the years ended December 31, 2016 or 2015.

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	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
Average daily throughput (MMcf/d)	502	415	478	21%	(13%)

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 behind the Mountaineer Midstream system 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.

Volume throughput declined during 2016, compared to the prior period, due to natural production declines which were not offset by new production as a result of Antero's decision to defer completion activities in the third quarter of 2015. Volume throughput during 2016 was also impacted by repairs on a third-party NGL pipeline located downstream of the Sherwood Processing Complex in June and July 2016 limiting the amount of natural gas we could deliver during the repair work.

Table of Contents

Financial data for our Marcellus Shale reportable segment follows.

	Marcellus Shale				
	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Revenues:					
Gathering services and related fees	$30,394	$26,111	$28,468	16%	(8%)
Total revenues	30,394	26,111	28,468	16%	(8%)
Costs and expenses:					
Operation and maintenance	6,057	6,506	4,886	(7%)	33%
General and administrative	449	402	368	12%	9%
Depreciation and amortization	9,047	8,841	8,682	2%	2%
Total costs and expenses	15,553	15,749	13,936	(1%)	13%
Add:					
Depreciation and amortization	9,047	8,841	8,682		
Segment adjusted EBITDA	$23,888	$19,203	$23,214	24%	(17%)

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.

Year ended December 31, 2016. Segment adjusted EBITDA decreased $4.0 million during 2016, compared to the prior period, primarily reflecting:

- a $2.4 million decrease in gathering services and related fees primarily as a result of lower volume throughput and lower compression revenues due to a shift in volume mix. These declines were partially offset by an increase in minimum revenue commitment payments.
- a $1.6 million increase in operation and maintenance primarily as a result of expenses associated with repairs to rights-of-way.

Table of Contents

Corporate and Other Overview for the Years Ended December 31, 2017, 2016 and 2015

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. Total revenue attributable to Corporate and other is $22.9 million for the year ended December 31, 2017 (see Note 3 to the consolidated financial statements). Other items to note follow.

	Corporate and Other				
	Year ended December 31,			Percentage Change	
	2017	2016	2015	2017 v. 2016	2016 v. 2015
	(Dollars in thousands)				
Costs and expenses:					
General and administrative	$47,507	$44,369	$32,942	7%	35%
Transaction costs	73	1,321	1,342	(94%)	(2%)
Interest expense (1)	68,131	63,810	59,092	7%	8%
Early extinguishment of debt (2)	22,039	—	—	*	*
Deferred Purchase Price Obligation	(200,322)	55,854	—	*	*

* Not considered meaningful

(1) Includes interest expense on debt allocated to the 2016 Drop Down Assets during the common control period.

(2) 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.

General and Administrative. General and administrative expense increased 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.

In the first quarter of 2015, the Partnership discontinued allocating certain administrative expenses, primarily salaries, benefits, incentive compensation and rent expense, to its then-reportable segments. As a result, the amount of expense allocated to and reported within the Company’s operating segments decreased, with a commensurate increase in corporate general and administrative expenses. This change, however, did not impact the historical results of entities under common control which were acquired subsequent to the first quarter of 2015. As a result, general and administrative expense allocations were higher for Polar and Divide and the 2016 Drop Down Assets during their respective common control periods because Summit Investments continued to allocate these administrative expenses to its non-Partnership subsidiaries. With respect to Polar and Divide, general and administrative expense allocations during the period from January 1, 2015 to May 18, 2015 included items that SMLP was no longer allocating to its then-operating segments. With respect to the 2016 Drop Down Assets, general and administrative expense allocations during the period from January 1, 2015 to March 3, 2016 included items that SMLP was no longer allocating to its then-operating segments. As such, subsequent to a given drop down, the application of the new expense allocation methodology to the newly acquired entities resulted in a decrease in reportable segment general and administrative

expenses and an increase in corporate general and administrative expenses.

The increase in general and administrative expenses recognized during the year ended December 31, 2016 primarily reflected the impact of a change in our expense allocation methodology and an increase in salaries, benefits and incentive compensation.

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. Transaction costs recognized during the year ended December 31, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down. Transaction costs in 2015 also include financial and legal advisory expenses incurred by Summit Investments for third-party acquisitions that were allocated to us in connection with the 2016 Drop Down.

Table of Contents

Interest Expense. 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.

The increase in interest expense during the year ended December 31, 2016 was primarily driven by (i) higher costs associated with increased borrowings on our Revolving Credit Facility and (ii) debt incurred by Summit Investments that was allocated to the Partnership in connection with the 2016 Drop Down. The Revolving Credit Facility borrowings incurred in March 2016 in connection with funding a portion of the 2016 Drop Down purchase price replaced the lower-rate Summit Investments' debt that had been allocated to us prior to our March 2016 closing of the 2016 Drop Down, resulting in an increase in interest expense.

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. 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.

Deferred Purchase Price Obligation recognized in 2016 relates to our March 2016 issuance of the deferred payment in connection with the 2016 Drop Down (see Notes 2 and 16 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. The 2017 SRS replaced the 2014 SRS which expired on July 10, 2017. 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.

The following transactions have been executed pursuant thereto:

- In November 2017, we issued 300,000 9.50% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual 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.

Table of Contents

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, 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, 2017, 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 9 and 11 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 9 to the consolidated financial statements). As of December 31, 2017, the outstanding balance of the Revolving Credit Facility was $261.0 million and the unused portion totaled $989.0 million. There were no defaults or events of default during the 2017 and, as of December 31, 2017, we were in

compliance with the covenants in the Revolving Credit Facility.

Senior Notes. In July 2014, the Co-Issuers co-issued the 5.5% Senior Notes, and in June 2013, they co-issued the 7.5% 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 2017 on any series of senior notes.

Table of Contents

For additional information on our long-term debt, see Notes 9 and 17 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 16 to the consolidated financial statements).

Cash Flows

Due to the common control aspect in a drop down transaction, we account for drop downs on an “as-if pooled” basis for the periods during which common control existed. As such, cash flows retrospectively reflect the cash flows associated with (i) the assets acquired from Summit Investments and (ii) the assets and liabilities allocated to the Partnership from Summit Investments.

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

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Net cash provided by operating activities	$237,832	$230,495	$191,375
Net cash used in investing activities	(148,683)	(534,126)	(646,720)
Net cash (used in) provided by financing activities	(95,147)	289,266	449,327
Net change in cash and cash equivalents	$(5,998)	$(14,365)	$(6,018)

Operating activities. 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.

Cash flows from operating activities for the year ended December 31, 2016, primarily reflected:

- a $10.4 million increase in distributions from Ohio Gathering;
- the prior-year impact of net cash paid for environmental remediation expenses; and
- cash received as a result of MVCs.

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

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 and Piceance/DJ Basins 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.

Table of Contents

Cash flows used in investing activities during the year ended December 31, 2015 primarily reflected:

- $288.6 million for our acquisition of the Polar and Divide system;
- $272.2 million of capital expenditures primarily attributable to the buildout of the gathering systems acquired in the 2016 Drop Down and the ongoing expansion of the Polar and Divide and Bison Midstream systems; and
- $86.2 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, 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.

Cash flows provided by financing activities during the year ended December 31, 2015 primarily reflected:

- $320.5 million of cash advances from Summit Investments to fund the development of the 2016 Drop Down Assets;
- $222.0 million of net proceeds from the issuance of common units in May 2015, of which $193.4 million was used to partially fund the Polar and Divide Drop Down;
- $216.0 million of net borrowings under our Revolving Credit Facility, of which $92.0 million was used to partially fund the Polar and Divide Drop Down;
- a $182.5 million repayment under Summit Investments' term loan; and
- $152.1 million of distributions paid in 2015.

Table of Contents

Contractual Obligations Update

The table below summarizes our contractual obligations as of December 31, 2017.

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt and interest payments (1)	$1,427,068	$60,818	$121,635	$672,740	$571,875
Deferred Purchase Price Obligation (2)	454,384	—	454,384	—	—
Purchase obligations (3)	94,568	94,568	—	—	—
Operating leases (4)	8,847	3,373	4,005	738	731
Total contractual obligations	$1,984,867	$158,759	$580,024	$673,478	$572,606

_____

(1) For the purpose of calculating future interest on the Revolving Credit Facility, assumes no change in balance or rate from December 31, 2017. Includes a 0.50% commitment fee on the unused portion of the Revolving Credit Facility. See Note 9 to the consolidated financial statements.

(2) See Note 16 to the consolidated financial statements.

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

(4) See Item 2. Properties and Note 15 to the consolidated financial statements.

In March 2016, we borrowed an additional $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 is currently expected to be $454.4 million based on information available as of December 31, 2017. There are no cash interest payments associated with the Deferred Purchase Price Obligation.

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 principal business strategy is to increase the amount of cash distributions we make to our unitholders over time. Our ability to grow 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. Our Partnership Agreement requires that we categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity; or
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

For the year ended December 31, 2017, cash paid for capital expenditures totaled $124.2 million, compared with $142.7 million for the year ended December 31, 2016 and $272.2 million for the year ended December 31, 2015 (see Note 3 to the consolidated financial statements). Maintenance capital expenditures totaled $15.6 million for the year ended December 31, 2017, compared with $17.7 million for the year ended December 31, 2016 and $12.7 million for

Table of Contents

the year ended December 31, 2015. For the year ended December 31, 2017, contributions to equity method investees totaled $25.5 million, compared with $31.6 million for the year ended December 31, 2016 and $86.2 million for the year ended December 31, 2015 (see Note 7 to the consolidated financial statements). The year-over-year declines in cash paid for capital expenditures primarily reflected the buildout in 2015 of recently acquired systems and the completion of several large capital projects on legacy systems.

The acquisition component and greenfield development projects of our principal business 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 external financing sources, including commercial bank borrowings and the issuance of debt, equity and preferred equity securities, to fund our acquisitions and expansion capital expenditures. We believe that our Revolving Credit Facility, together with financial support from our Sponsor and/or access to the debt and 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.

Distributions, Including IDRs

Based on the terms of our Partnership Agreement, we expect to distribute most of the cash generated by our operations to our unitholders. With respect to our payment of IDRs to the General Partner, we reached the second target distribution in connection with the distribution declared in respect of the fourth quarter of 2013. We reached the third target distribution in connection with the distribution declared in respect of the second quarter of 2014. For additional information, see Note 11 to the consolidated financial statements.

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.

Given the current environment, 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 customer’s wellheads and pad sites, which means our gathering systems are typically the first third-party infrastructure through which our customer’s 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 their 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

For additional information, see Notes 3, 8 and 10 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, 2017.

Table of Contents

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, 2017, we had net property, plant and equipment with a carrying value of approximately $1.8 billion and net amortizing intangible assets with a carrying value of approximately $301.3 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.

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 relating 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.

For additional information, see Notes 2, 4 and 5 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.

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

2015 Impairment Evaluations. During the latter part of the fourth quarter of 2015 and the early part of the first quarter of 2016, the declines in forward prices for natural gas, NGLs and crude oil accelerated significantly. As a result, the energy sector's public debt and equity market experienced increased volatility, particularly for comparable companies operating in the midstream services sector. Additionally, during this period, the values of our publicly traded equity

Table of Contents

and debt instruments decreased as did those of comparable midstream companies. Due to (i) the increased market volatility, (ii) the decrease in market values of comparable companies, (iii) the continued trend of falling commodity prices and (iv) the finalization of our annual financial and operating plans which took into account changes resulting from expected levels of drilling activity, we concluded that a triggering event occurred which required that we test the goodwill associated with our Grand River and Polar and Divide reporting units for impairment as of December 31, 2015. In connection therewith, we concluded that the goodwill associated with our Grand River and Polar and Divide reporting units was fully impaired and we wrote off the associated balances.

See Notes 2 and 6 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 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 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 Note 16 to the consolidated financial statements for additional information.

Minimum Volume Commitments

Certain of our gathering agreements provide for a monthly, quarterly or annual MVC from our customers. As of December 31, 2017, we had MVCs totaling 1.0 Bcfe/d through 2022.

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 period.

We recognize customer billings for obligations under their MVCs as revenue when the obligations are billable under the contract and the customer does not have the right to utilize shortfall payments to offset gathering fees in excess of its MVCs in subsequent periods.

We billed $63.1 million of MVC shortfall payments to customers that did not meet their MVCs during 2017. For those customers that do not have credit banking mechanisms in their gathering agreements, or have no ability to use MVC shortfall payments as credits, the MVC shortfall payments from these customers are accounted for as gathering revenue in the period that they are earned. We recognized $53.9 million of gathering revenue due to the credit bank

Table of Contents

expiration of previous MVC shortfall payments and previously deferred revenue as gathering services and related fees (see Note 8 to the consolidated financial statements). Adjustments to MVC shortfall payments in 2017 totaled ($41.4) million and included adjustments related to future anticipated shortfall payments from certain customers in the Williston Basin, Piceance/DJ Basins and Barnett Shale segments.

The following table presents the impact of our MVC activity by reportable segment during the year ended December 31, 2017.

	Year ended December 31, 2017		
	MVC Billings	Gathering revenue	Adjustments to MVC shortfall payments
	(In thousands)		
Net change in deferred revenue related to MVC shortfall payments:			
Utica Shale	$—	$—	$ —
Williston Basin	—	37,693	(37,693)
Piceance/DJ Basins	13,106	16,171	(3,065)
Barnett Shale	—	—	—
Marcellus Shale	—	—	—
Total net change	$13,106	$53,864	$ (40,758)
MVC shortfall payment adjustments:			
Utica Shale	$—	$—	$ —
Williston Basin	12,958	12,958	—
Piceance/DJ Basins	28,608	28,608	(3)
Barnett Shale	4,032	4,032	(612)
Marcellus Shale	4,398	4,398	—
Total MVC shortfall payment adjustments	$49,996	$49,996	$ (615)
Total	$63,102	$103,860	$ (41,373)

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 once all contingencies or potential performance obligations associated with the related volumes have either (i) been satisfied through the gathering or processing of future excess volumes of natural gas, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable gathering agreement. 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, 2017, current deferred revenue totaled $4.0 million. Noncurrent deferred revenue totaled $12.7 million at December 31, 2017 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 MVC shortfall payments. We include a proportional amount of these historical or expected MVC shortfall payments in our calculation of segment adjusted EBITDA each quarter

Table of Contents

until we actually recognize the shortfall payment. These adjustments have not been billed to our customers and are not recognized in our consolidated financial statements.

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, 3 and 8 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 officials 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 b “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “wou 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:

- 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 and crude oil 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;
- our ability to acquire assets owned by third parties, which is subject to a number of factors, including prevailing conditions and outlook in the natural gas, NGL and crude oil industries and markets and our ability to obtain financing on acceptable terms;
- the ability to attract and retain key management personnel;
- commercial bank and capital market conditions and the potential impact of changes or disruptions in the credit and/or 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 capital markets;

- restrictions placed on us by the agreements governing our debt instruments;

Table of Contents

- 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.

Table of Contents

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, 2017, we had $800.0 million principal of fixed-rate Senior Notes and $261.0 million outstanding under our variable rate Revolving Credit Facility (see Note 9 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, 2017, a hypothetical 1% increase (decrease) in interest rates would have increased (decreased) our interest expense by approximately $4.9 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 substantial 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 system customers and (iv) the sale of condensate we retain from our gathering services at Grand River. Our gathering agreements with certain DFW Midstream system 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. Because we also sell our retainage gas at prices that are based on the Waha Hub Index, we have effectively fixed the relationship between our compression electricity expense and natural gas sales. We do not enter into risk management contracts for speculative purposes.

Table of Contents

Item 8. Financial Statements and Supplementary Data.

Table of Contents

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, 2017 and 2016, the related consolidated statements of operations, partners' capital, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with 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, 2017 and 2016 or Ohio Condensate Company, L.L.C. ("Ohio Condensate") as of and 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 $683,468,000 and $700,608,000 as of December 31, 2017 and 2016, respectively, and Ohio Condensate of $6,807,000 as of December 31, 2016, and its income (loss) from equity method investees in Ohio Gathering of $(1,823,000) and $7,451,000 for the years ended December 31, 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, 2017, 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, 2018 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 report of the other auditors provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 26, 2018

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

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$1,430	$7,428
Accounts receivable	72,301	97,364
Other current assets	4,327	4,309
Total current assets	78,058	109,101
Property, plant and equipment, net	1,795,129	1,853,671
Intangible assets, net	301,345	421,452
Goodwill	16,211	16,211
Investment in equity method investees	690,485	707,415
Other noncurrent assets	13,565	7,329
Total assets	$2,894,793	$3,115,179
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$16,375	$16,251
Accrued expenses	12,499	11,389
Due to affiliate	1,088	258
Deferred revenue	4,000	—
Ad valorem taxes payable	8,329	10,588
Accrued interest	12,310	17,483
Accrued environmental remediation	3,130	4,301
Other current liabilities	11,258	11,471
Total current liabilities	68,989	71,741
Long-term debt	1,051,192	1,240,301
Deferred Purchase Price Obligation	362,959	563,281
Deferred revenue	12,707	57,465
Noncurrent accrued environmental remediation	2,214	5,152
Other noncurrent liabilities	7,063	7,566
Total liabilities	1,505,124	1,945,506
Commitments and contingencies (Note 15)		
Series A Preferred Units (300 units issued and outstanding at December 31, 2017)	294,426	—
Common limited partner capital (73,086 units issued and outstanding at December 31, 2017 and 72,111 units issued and outstanding at	1,056,510	1,129,132

December 31, 2016)		
General Partner interests (1,491 units issued and outstanding at December 31, 2017 and 1,471 units issued and outstanding at December 31, 2016)	27,920	29,294
Noncontrolling interest	10,813	11,247
Total partners' capital	1,389,669	1,169,673
Total liabilities and partners' capital	$2,894,793	$3,115,179

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

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2017	2016	2015
	(In thousands, except per-unit amounts)		
Revenues:			
Gathering services and related fees	$394,427	$345,961	$337,819
Natural gas, NGLs and condensate sales	68,459	35,833	42,079
Other revenues	25,855	20,568	20,659
Total revenues	488,741	402,362	400,557
Costs and expenses:			
Cost of natural gas and NGLs	57,237	27,421	31,398
Operation and maintenance	93,882	95,334	94,986
General and administrative	54,681	52,410	45,108
Depreciation and amortization	115,475	112,239	105,117
Transaction costs	73	1,321	1,342
Environmental remediation	—	—	21,800
Loss (gain) on asset sales, net	527	93	(172)
Long-lived asset impairment	188,702	1,764	9,305
Goodwill impairment	—	—	248,851
Total costs and expenses	510,577	290,582	557,735
Other income	298	116	2
Interest expense	(68,131)	(63,810)	(59,092)
Early extinguishment of debt	(22,039)	—	—
Deferred Purchase Price Obligation	200,322	(55,854)	—
Income (loss) before income taxes and loss from equity method investees	88,614	(7,768)	(216,268)
Income tax (expense) benefit	(341)	(75)	603
Loss from equity method investees	(2,223)	(30,344)	(6,563)
Net income (loss)	$86,050	$(38,187)	$(222,228)
Less:			
Net income (loss) attributable to Summit Investments	—	2,745	(30,016)
Net income (loss) attributable to noncontrolling interest	363	(14)	—
Net income (loss) attributable to SMLP	85,687	(40,918)	(192,212)
Less net income (loss) attributable to General Partner, including IDRs	10,202	7,261	3,398
Net income (loss) attributable to limited partners	75,485	(48,179)	(195,610)
Less net income attributable to Series A Preferred Units	3,563	—	—
Net income (loss) attributable to common limited partners	$71,922	$(48,179)	$(195,610)

Earnings (loss) per limited partner unit:			
Common unit – basic	$0.99	$(0.71)	$(3.20)
Common unit – diluted	$0.98	$(0.71)	$(3.20)
Subordinated unit – basic and diluted			$(2.88)
Weighted-average limited partner units outstanding:			
Common units – basic	72,705	68,264	39,217
Common units – diluted	73,047	68,264	39,217
Subordinated units – basic and diluted			24,410

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

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Partners' capital			Summit Investments' equity in contributed subsidiaries	
	Limited partners				
	Common	Subordinated	General Partner		Total
	(In thousands)				
Partners' capital, January 1, 2015	$649,060	$ 293,153	$24,676	$ 863,789	$1,830,678
Net (loss) income	(123,817)	(71,793)	3,398	(30,016)	(222,228)
Distributions to unitholders	(86,880)	(55,410)	(9,784)	—	(152,074)
Unit-based compensation	6,174	—	—	—	6,174
Tax withholdings on vested SMLP LTIP awards	(1,616)	—	—	—	(1,616)
Issuance of common units, net of offering costs	221,977	—	—	—	221,977
Contribution from General Partner	—	—	4,737	—	4,737
Purchase of Polar and Divide	—	—	—	(285,677)	(285,677)
Excess of acquired carrying value over consideration paid for Polar and Divide	80,079	47,681	2,607	(130,367)	—
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	320,527	320,527
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	22,879	22,879
Capitalized interest allocated to contributed subsidiaries from Summit Investments	—	—	—	1,079	1,079
Class B membership interest noncash compensation	—	—	—	843	843
Partners' capital, December 31, 2015	$744,977	$ 213,631	$25,634	$ 763,057	$1,747,299

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

(continued)

	Partners' capital					
	Limited partners				Summit Investments' equity in	
	Common	Subordinated	General Partner	Noncontrolling interest	contributed subsidiaries	Total
	(In thousands)					
Partners' capital, December 31, 2015	$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	—	—	—	—	12,214	12,214

Investments to contributed subsidiaries, net						
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	—	4,821	4,821
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

103

Table of Contents

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	$294,426	$1,056,510	$ 27,920	$ 10,813	$1,389,669

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

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$86,050	$(38,187)	$(222,228)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	114,872	112,661	105,903
Amortization of debt issuance costs	4,158	3,976	4,309
Deferred Purchase Price Obligation	(200,322)	55,854	—
Unit-based and noncash compensation	7,951	7,985	7,017
Loss from equity method investees	2,223	30,344	6,563
Distributions from equity method investees	40,220	44,991	34,641
Loss (gain) on asset sales, net	527	93	(172)
Long-lived asset impairment	188,702	1,764	9,305
Goodwill impairment	—	—	248,851
Early extinguishment of debt	22,039	—	—
Write-off of debt issuance costs	302	—	727
Changes in operating assets and liabilities:			
Accounts receivable	25,063	(7,783)	3,328
Insurance receivable	—	—	25,000
Trade accounts payable	(3,246)	2,001	(1,450)
Accrued expenses	1,110	4,613	(1,967)
Due from (to) affiliate	830	(891)	1,377
Deferred revenue, net	(40,758)	11,302	(11,453)
Ad valorem taxes payable	(2,259)	317	1,092
Accrued interest	(5,173)	—	(1,375)
Accrued environmental remediation, net	(4,109)	(4,211)	(16,336)
Other, net	(348)	5,666	(1,757)
Net cash provided by operating activities	237,832	230,495	191,375
Cash flows from investing activities:			
Capital expenditures	(124,215)	(142,719)	(272,225)
Proceeds from asset sale	2,300	—	—
Contributions to equity method investees	(25,513)	(31,582)	(86,200)
Acquisitions of gathering systems from affiliate, net of acquired cash	—	(359,431)	(288,618)
Purchase of noncontrolling interest	(797)	—	—
Other, net	(458)	(394)	323
Net cash used in investing activities	(148,683)	(534,126)	(646,720)

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(continued)

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	(181,478)	(167,504)	(152,074)
Borrowings under Revolving Credit Facility	247,500	520,300	367,000
Repayments under Revolving Credit Facility	(634,500)	(204,300)	(151,000)
Repayments under term loan	—	—	(182,500)
Debt issuance costs	(16,390)	(3,032)	(412)
Payment of redemption and call premiums on senior notes	(17,932)	—	—
Proceeds from ATM Program common unit issuances, net of costs	17,078		