Summit Midstream Partners, LP
Form 10-K
March 02, 2015
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-35666
Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

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

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

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the common units held by non-affiliates of the registrant as of June 30, 2014, was $1,260,163,276.

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.

Class	As of January 31, 2015
Common Units	34,426,513 units
Subordinated Units	24,409,850 units
General Partner Units	1,200,651 units

TABLE OF CONTENTS

Table of Contents

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 “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 or our subsidiaries, are also forward-looking statements. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described under the section entitled “Risk Factors” included herein.

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, natural gas liquids ("NGLs") and crude oil prices;
- the extent and success of drilling efforts, as well as the extent and quality 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 and crude oil 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 non-performance 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;
- our ability to acquire any assets owned by Summit Midstream Partners, LLC ("Summit Investments"), which is subject to a number of factors, including Summit Investments deciding, in its sole discretion, to offer us the right to acquire such assets, the ability to reach agreement on acceptable terms, the approval of the conflicts committee of our general partner's board of directors (if appropriate), prevailing conditions and outlook in the natural gas, NGL and crude oil industries and markets, and our ability to obtain financing on acceptable terms from the credit and/or capital markets or other sources;
- our ability to consummate acquisitions, successfully integrate the acquired businesses, realize any cost savings and other synergies from any acquisition;
- 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;
- 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 processing of natural gas;
- weather conditions and seasonal trends;
- 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 and climate change requirements;

Table of Contents

- 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 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

Glossary of Terms

adjusted EBITDA: EBITDA plus adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less other noncash income or gains

AMI: area of mutual interest; AMIs require that any production from natural gas wells drilled by our customers within the AMI be shipped on 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

Bcf: one billion cubic feet

condensate: a natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions

conventional resource basin: a basin where natural gas production is developed from a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the crude oil and natural gas to readily flow to the wellbore; also referred to as a conventional resource play

delivery point: the point where hydrocarbons are delivered into a gathering system, processing or fractionation facility or downstream transportation pipeline

distributable cash flow: adjusted EBITDA plus cash interest received, less cash interest paid, senior notes interest, cash taxes paid and maintenance capital expenditures

dry gas: a gas primarily composed of methane where heavy hydrocarbons and water either do not exist or have been removed through processing

EBITDA: net income or loss, plus interest expense, income tax expense, and depreciation and amortization, less interest income and income tax benefit

end users: the ultimate users and consumers of transported energy products

Mcf: one thousand cubic feet

MMBtu: one million British Thermal Units

MMcf: one million cubic feet

MMcf/d: one million cubic feet per day

MQD: minimum quarterly distribution; our partnership agreement has established a minimum quarterly distribution of $0.40 per unit per quarter, or $1.60 per unit per year

MVC: minimum volume commitment; an MVC contractually obligates a customer to ship on our systems and/or use our processing services for a minimum quantity of natural gas

NGLs: natural gas liquids; the combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature

play: a proven geological formation that contains commercial amounts of hydrocarbons

receipt point: the point where hydrocarbons are received by or into a gathering system or transportation pipeline

residue gas: the natural gas remaining after being processed or treated

segment adjusted EBITDA: calculated as adjusted EBITDA excluding the impact of the corporate expenses that we allocate to our reportable segments

Table of Contents

shortfall payment: the payment received from a counterparty when its volume throughput does not meet its MVC for the applicable period
tailgate: refers to the point at which processed residue natural gas and NGLs leave a processing facility for end-use markets
Tcf: one trillion cubic feet
throughput volume: the volume of natural gas transported or passing through a pipeline, plant or other facility during a particular period; also referred to as volume throughput
unconventional resource basin: a basin where natural gas 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
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

Industry Overview

General

The midstream segment of the natural gas industry is the link between the exploration and production of natural gas from the wellhead and the delivery of the natural gas and its other components to end-use markets. Companies within this industry create value at various stages along the natural gas value chain by gathering natural gas from producers at the wellhead, separating the hydrocarbons into dry gas and NGLs and then routing the separated dry gas and NGLs streams for delivery to end-markets or to the next intermediate stage of the value chain. The following diagram illustrates the assets commonly found along the natural gas value chain:

Midstream Services

The range of services provided by midstream natural gas service companies are generally divided into the following six categories:

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads, pad sites or other receipt points in the production area. These gathering systems transport natural gas from the wellhead to downstream pipelines or a central location for treating

Table of Contents

and processing. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow for additional production and well connections.

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

Treating and Dehydration. Treating and dehydration involves the removal of impurities such as water, carbon dioxide, nitrogen and hydrogen sulfide, which may be present when natural gas is produced at the wellhead. These impurities must be removed for the natural gas to meet the specifications for transportation on long-haul intrastate and interstate pipelines. Moreover, end users will not purchase natural gas with high levels of impurities.

Processing. The principal components of natural gas are methane and ethane. Most natural gas also contains varying amounts of other NGLs. Even after treating and dehydration, some natural gas is not suitable for long-haul intrastate and interstate pipeline transportation or commercial use because it contains NGLs and condensate. This natural gas, referred to as liquids-rich natural gas, must also be processed to remove these heavier hydrocarbon components. NGLs not only interfere with pipeline transportation, but are also valuable commodities once removed from the natural gas stream. The removal and separation of NGLs usually takes place in a processing plant and fractionation facility using industrial processes that exploit differences in the weights, boiling points, vapor pressures and other physical characteristics of NGL components.

Fractionation. Fractionation is the process by which NGLs are separated into individual liquid products for sale to petrochemical and industrial end users. The NGL components that can be separated in fractionation generally include: ethane, propane, normal butane, iso-butane and natural gasoline. This mixture of raw NGLs is often referred to as y-grade or raw natural gas liquid mix.

Transportation and Storage. After treating and dehydration, processing and fractionation, the natural gas and NGL components are either stored or transported and marketed to end-use markets. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

Contractual Arrangements

Midstream natural gas services, other than transportation and storage, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical types of contracts are described below.

Fee-Based. Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered and/or compressed at the wellhead and an additional fee per unit of natural gas treated or processed at its facility. As a result, the service provider bears no direct commodity price risk exposure.

Percent-of-Proceeds. Under percent-of-proceeds arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the gatherer/processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas condensate and NGLs.

Keep-Whole. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the natural gas, is returned to the producer. Since some of the natural gas is used and removed during processing, the processor compensates the producer for the amount of natural gas used and removed in processing by supplying additional natural gas or by paying an agreed-upon value for the natural gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

Table of Contents

PART I

Item 1. Business.

Summit Midstream Partners, LP ("SMLP") is a Delaware limited partnership that completed its initial public offering ("IPO") on October 3, 2012 to become a publicly traded entity. Summit Investments is a Delaware limited liability company and the predecessor for accounting purposes (the "Predecessor") of SMLP. References to the "Company," "we," or "our," when used for dates or periods ended on or after the IPO, refer collectively to SMLP and its subsidiaries. References to the "Company," "we," or "our," when used for dates or periods ended prior to the IPO, refer collectively to Summit Investments and its subsidiaries. For additional information, see Note 1 to the audited consolidated financial statements.

Item 1. Business is divided into the following sections:

- Overview
- Business Strategies
- Competitive Strengths
- Our Midstream Assets
- Regulation of the Natural Gas and Crude Oil Industries
- Environmental Matters
- Other Information

Overview

SMLP is a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America. We provide natural gas gathering, treating and processing services pursuant to primarily long-term and fee-based natural gas gathering and processing agreements with our customers and counterparties. We generally refer to all of the services provided as gathering services.

We currently operate in four unconventional resource basins:

- the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

Our systems and the basins they serve are as follows:

- the Mountaineer Midstream system, which serves the Appalachian Basin;
- the Bison Midstream system, which serves the Williston Basin;
- the DFW Midstream system, which serves the Fort Worth Basin; and
- the Grand River system, which serves the Piceance Basin.

We have a diverse group of customers and counterparties comprising affiliates and/or subsidiaries of some of the largest crude oil and natural gas producers in North America. Our anchor customers and the systems they serve are as follows:

- Antero Resources Corp. ("Antero"), which is the anchor for the Mountaineer Midstream system ("Mountaineer Midstream");
- EOG Resources, Inc. ("EOG") and Oasis Petroleum, Inc. ("Oasis"), which are the anchors for the Bison Midstream system ("Bison Midstream");
- Chesapeake Energy Corporation ("Chesapeake"), which is the anchor for the DFW Midstream system ("DFW Midstream"); and

Table of Contents

- Encana Corporation ("Encana") and WPX Energy, Inc. ("WPX"), which are the anchors for the Grand River system ("Grand River").

A significant percentage of our revenue is attributable to these anchor customers. (For additional information on customer concentrations, see Note 11 to the audited consolidated financial statements.)

Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. As of December 31, 2014, our gathering systems had more than 2,300 miles of pipeline and over 250,000 horsepower of compression. During 2014, we gathered an average of 1,418 MMcf/d of natural gas.

We generate a substantial majority of our revenue under long-term, primarily fee-based natural gas gathering agreements. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure. During the year ended December 31, 2014, we generated approximately 94% of our revenue, net of pass-through items, from fee-based gathering services. In addition, substantially all of our gas gathering and processing agreements include areas of mutual interest ("AMIs"). Our AMIs cover more than 1.4 million acres in the aggregate.

Certain of our gas gathering and processing agreements include minimum volume commitments or minimum revenue commitments (collectively referred to as "MVCs"). To the extent the customer does not meet its MVC, it must make payments to cover the shortfall of natural gas not shipped or 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 respective gas 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, 2014, we had remaining MVCs totaling 3.8 Tcf. Our MVCs have a weighted-average remaining life of 9.7 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1,248 MMcf/d through 2018.

We believe that we are positioned for growth through the increased utilization and further development of our existing midstream assets. In addition, we 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. We also intend to continue expanding our operations and diversifying our geographic footprint through asset acquisitions from Summit Investments and third parties, although Summit Investments has no obligation to offer any assets to us and we have no obligation to acquire the assets that they offer to us, if any.

Organization and Results of Operations

SMLP was formed in May 2012 in anticipation of our IPO. Since the IPO, we have issued additional common units and general partner interests in connection with two drop down transactions, one third-party acquisition and certain unit-based compensation awards. As of December 31, 2014, Summit Investments, through a wholly owned subsidiary, held 5,293,571 SMLP common units, 24,409,850 SMLP subordinated units and 1,200,651 general partner units representing a 2% general partner interest in SMLP, along with all of the incentive distribution rights ("IDRs") issued by SMLP. For additional information, see Notes 1, 8 and 15 to the audited consolidated financial statements.

Summit Investments was formed in 2009 by members of our management team and our Sponsor, Energy Capital Partners. Due to its ownership interest in Summit Investments and its representation on Summit Investments' board of managers, Energy Capital Partners controls our general partner and its activities, and as a result, SMLP.

We currently conduct our natural gas gathering, treating and processing operations in the midstream sector through our four natural gas gathering systems, each of which represents one of our four reportable segments. 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. The primary assets of each of our reportable segments consist of natural gas gathering systems and related property, plant and equipment.

Our financial results are primarily driven by the volumes of natural gas that we gather, treat and process across our systems and our management of expenses. We use a variety of financial and operational metrics to analyze our performance, including among others, throughput volume, revenues, operation and maintenance expense, EBITDA, adjusted EBITDA and distributable cash flow. For additional information on our results of operations, reportable segment disclosures, EBITDA, adjusted EBITDA and distributable cash flow, see Item 6. Selected Financial Data, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), and the audited consolidated financial statements and notes thereto included in this report.

2

Table of Contents

Our Sponsor

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 indirectly owns our general partner, has an inventory of midstream assets and joint venture interests comprising more than $2.3 billion of previous acquisitions and current and future development projects. In addition to its midstream assets located in the Denver-Julesburg ("DJ") Basin in Colorado, the Utica Shale in Ohio, and the Williston Basin in North Dakota, Summit Investments also participates in a joint venture which is developing a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate stabilization facility in the southeastern core of the Utica Shale. Each of these assets provide us with opportunities for customer and service offering diversification into crude oil and/or produced water gathering, dry gas gathering and liquids-rich natural gas gathering and processing. Furthermore, we believe these assets present an opportunity to further diversify our operations geographically. While these assets have not been contributed to SMLP and Summit Investments or its affiliates is not obligated to sell these assets to us, we believe they represent a future opportunity for execution of our business strategy.

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:

- Pursuing accretive acquisition opportunities from Summit Investments. We intend to pursue opportunities to expand our asset base by acquiring midstream assets and joint venture interests that are owned, operated and under development by Summit Investments. In addition to its significant ownership interest in us, Summit Investments owns and operates, and seeks to acquire and develop, crude oil, natural gas and water-related midstream assets in service and under construction in geographic areas in which we currently operate as well as in geographic areas outside of our current areas of operations. For example, in December 2014, Summit Investments announced an agreement to develop and operate a new 500 MMcf/d natural gas gathering system in the Utica Shale ("Summit Utica"). Summit Utica will gather, compress and deliver natural gas produced by XTO Energy Inc. into Regency Energy Partners LP's 2.1 Bcf/d high-pressure Utica Ohio River Trunkline Project, which is currently under construction, and other downstream delivery points. While Summit Investments has indicated that it intends to offer us the opportunity to acquire its interests in its various midstream assets, it is not under any contractual obligation to do so and we are unable to predict whether or when such opportunities may arise. In its role as a midstream development vehicle for our Sponsor, we believe that Summit Investments' development efforts mitigate potential development and cash flow timing risks associated with large-scale greenfield development projects that would otherwise be borne by us.
- 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 up to 25 years. Currently, all of the contracts associated with assets owned and being developed by Summit Investments are fee based. We believe that our focus on fee-based revenues with minimal direct commodity 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 and exploring acquisition and development opportunities in various geographic areas. Our natural gas gathering operations in the Marcellus, Bakken, Three

Forks and Barnett shale plays and the Piceance Basin currently represent our core business. However, in the future, we intend to diversify our service offerings into crude oil and

Table of Contents

produced water gathering. We also intend to diversify our operations into other geographic regions, through both greenfield development projects and acquisitions from affiliated and non-affiliated parties.

- 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 anchor customers and commit to long-term MVCs and 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 four established unconventional resource basins. The geologic formations in the basins served by our assets have either relatively low drilling and completion costs, highly economic production profiles, or a combination of both which incent 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 revenue for the year ended December 31, 2014 was generated under long-term and fee-based gas gathering and processing agreements. We believe that long-term, fee-based gas 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, 2014, we had $808.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated senior secured revolving credit facility (the "revolving credit facility") totaled $492.0 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 approximately 3.9 to 1.0 at December 31, 2014, which compares with a total leverage ratio upper limit of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to 270 days following certain acquisitions (as defined in the credit agreement).
- Experienced management team with a proven record of asset acquisition, construction, development, operations and integration expertise. Our senior leadership team has an average of 20 years of energy experience and a proven track record of identifying, consummating and integrating significant acquisitions in addition to partnering with major producers to construct and develop midstream energy infrastructure.
- Relationship with a large and committed financial sponsor. Our Sponsor, Energy Capital Partners, is an experienced energy investor with a proven track record of making substantial, long-term investments in high-quality energy assets. We believe that the relationship with 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.

Our Midstream Assets

Our midstream assets currently consist of four natural gas gathering systems:

- Mountaineer Midstream in northern West Virginia;
- Bison Midstream in northwestern North Dakota;
- DFW Midstream in north-central Texas; and
- Grand River in western Colorado and eastern Utah.

We compete with other midstream companies, producers and intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, service levels, access to end-use markets,

Table of Contents

location and available capacity. We may also face competition to gather production drilled 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 natural gas gathering, treating and processing services pursuant to primarily long-term and fee-based natural gas gathering and processing agreements with some of the largest and most active producers in North America. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

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

Areas of Mutual Interest

A substantial majority of our gathering and processing agreements contain AMIs. The AMIs generally have original terms up to 25 years and require that any production by our customers within the AMIs will be shipped on our gathering systems. Our customers do not have leased production acreage that currently cover our entire AMIs but, to the extent that our customers lease additional acreage in the future within our AMIs, natural gas produced by our customers from that leased acreage is required to be gathered and/or processed by our systems.

Under certain of our gas 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 discretionary opportunity presented by a customer because we believe that the project would not meet our economic return expectations. Under this scenario, the customer may, in certain circumstances, construct the additional infrastructure 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

Many of our gas gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of natural gas on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. The original terms of our MVCs range from two to 15 years and had a weighted-average remaining life of 9.7 years as of December 31, 2014. In addition, certain of our customers have an aggregate MVC, which is a total amount of natural gas that the customer has agreed to ship 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.

In addition to AMIs, MVCs are beneficial in connection with the development and ongoing operation of a gathering system because they provide a contracted portfolio at start up and limit our direct commodity price exposure during the life of the gathering system.

For additional information on our MVCs, see the "Critical Accounting Estimates" section in MD&A and Notes 2 and 6 to the audited consolidated financial statements.

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”). We refer to these assets as the Mountaineer Midstream system. The Mountaineer Midstream 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 newly constructed, high-pressure natural gas gathering pipelines ranging from 8 inches to 20 inches in diameter and two compressor stations. This rich-gas gathering and compression system serves as a critical inlet to MarkWest's Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia. The Mountaineer Midstream system currently provides our midstream services for the Marcellus Shale reportable segment.

During the third quarter of 2014, throughput capacity was increased to 1,050 MMcf/d to support Antero's current and future anticipated drilling activities. We expect volumes to continue to grow on this system during 2015 as new

Antero wells are connected by other third parties upstream of our system.

Table of Contents

The following table provides information regarding our Mountaineer Midstream system as of December 31, 2014.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)
Mountaineer Midstream (1)	49	21,330	1,050

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

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, 20-inch pipeline on the Mountaineer Midstream system (the "Zinnia Loop"). The Zinnia Loop project is underpinned by a new, 12-year, minimum revenue commitment from Antero, which extends the original term of the contract through 2026. With this expansion, we believe the Mountaineer Midstream system will enhance its strategic position as a primary source of natural gas deliveries to the Sherwood Processing Complex.

Bison Midstream

In June 2013, we acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Williston Basin in northwestern North Dakota from a subsidiary of Summit Investments. We refer to these assets as the Bison Midstream system. The Bison Midstream system 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 and producer drilling decisions and activity are based largely on the prevailing price of crude oil. As such, natural gas volume throughput is also impacted by the prevailing price of crude oil. Our gas gathering agreements for the Bison Midstream system are long-term, primarily fee-based, contracts ranging from five years to 15 years and provide diversity of commodity price exposure for us relative to our other natural gas midstream operations. The Bison Midstream system currently provides our midstream services for the Williston Basin reportable segment.

The Bison Midstream system, which is located in Mountrail and Burke counties, consists of low- and high-pressure pipeline and six compressor stations and includes gathering lines ranging from 3 inches to 10 inches in diameter. 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 its 2.1 Bcf/d natural gas processing plant in Channahon, Illinois.

Total throughput capacity on the system is in the process of being expanded from 26 MMcf/d to 32 MMcf/d with the installation of new compression which is expected to be completed by the end of the first quarter of 2015. Volume throughput on the Bison Midstream system is underpinned by MVCs from its anchor customers, EOG and Oasis.

The following table provides information regarding our Bison Midstream system as of December 31, 2014.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2018 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Bison Midstream	391	9,770	26	676,500	12	20	5.6

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

In addition to its fee-based gas gathering agreement with EOG and percent-of-proceeds gas gathering agreement with Oasis, the Bison Midstream system is also supported by other fee-based gas gathering agreements. As of December 31, 2014, these gas gathering agreements had AMIs extending through 2027. We continue to develop the Bison Midstream system to extend our gathering reach, increase capacity, increase our receipt points and maximize throughput. Since its acquisition, we have increased capacity and improved system reliability by adding pipeline, continuing to connect additional pad sites located within our AMIs, and installing additional compression.

DFW Midstream

In September 2009, we acquired approximately 17 miles of pipeline and 2,500 horsepower of electric-drive compression in north-central Texas from Energy Future Holdings Corp. ("Energy Future Holdings") and Chesapeake. We refer to these assets as the DFW Midstream system. Since the initial acquisition, we have expanded this system by adding pipeline and continuing to connect additional pad sites located within our AMIs. In addition, we have expanded throughput capacity by installing additional electric-drive compression for which we retain a small fixed percentage of the natural gas that we receive to offset the costs we incur to operate our electric-drive compressors. The DFW Midstream system is primarily located in southeastern Tarrant County, 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. The DFW Midstream system includes gathering lines ranging from 4 inches to 30 inches in diameter and is located along existing electric transmission corridors and under both private and public property. It currently has six primary interconnections with third-party, intrastate pipelines. These interconnections enable us to connect our customers, directly or indirectly, with the major natural gas market hubs of Waha, Carthage, and Katy in Texas, and Perryville and Henry Hub in Louisiana. The DFW Midstream system currently provides our midstream services for the Barnett Shale reportable segment.

The DFW Midstream system benefits from its location in southeastern Tarrant County, Texas, which is commonly referred to as the core of the Barnett Shale. Based on peak month average daily production rates sourced from the Railroad Commission of Texas as of December 2014, this area contains the most prolific wells in the Barnett Shale. For example, the two largest and five of the ten largest wells drilled in the Barnett Shale (based on peak month average daily rates) are connected to the DFW Midstream system.

We designed the DFW Midstream system 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 sites. We believe that the AMIs underpinning our system are substantially undeveloped compared with other areas in the Barnett Shale due to the historical lack of gathering infrastructure.

The following table provides information regarding our DFW Midstream system as of December 31, 2014.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2018 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
DFW Midstream	128	66,100	480	108,300	131	191	4.9

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

In September 2009, we entered into a long-term, fee-based gas gathering agreement with Chesapeake as our anchor customer that included a 20-year area of mutual interest covering approximately 95,000 acres and a 10-year MVC totaling approximately 450 Bcf. In addition to Chesapeake, the DFW Midstream system is underpinned by other long-term, fee-based gas gathering agreements.

We continue to develop the DFW Midstream system to extend our gathering reach, diversify our customer base, increase our receipt points and maximize throughput. For example, in February 2014, we commissioned a 150 gallon per minute natural gas treating facility that allows us to provide treating services that would otherwise be provided to our customers by third parties. Additionally, in September 2014, we acquired certain natural gas gathering assets which increased throughput capacity on the DFW Midstream system by approximately 30 MMcf/d. We believe our strategic location in the Barnett Shale provides us with a competitive advantage to add incremental throughput with limited additional investment capital due to the anticipated future, high-density, infill drilling from our customers on connected pad sites and nearby pad sites that have yet to be connected given the urban landscape and the efforts of our producer customers to minimize their surface footprint. Furthermore, we believe the production profile of wells drilled within our AMIs and flowing on the DFW Midstream system will continue to attract drilling activity over the long term as producers become more selective in their drilling locations and focus on the core areas of certain basins to maximize their returns.

Grand River

In October 2011, Grand River acquired certain natural gas gathering pipeline, dehydration and compression assets in the Piceance Basin in western Colorado from Encana Oil & Gas (USA) Inc., a subsidiary of Encana. These assets gather natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin in western Colorado. They are primarily located in Garfield County, the largest natural gas

Table of Contents

producing county in Colorado. We refer to the assets that we acquired in October 2011 as the Legacy Grand River system.
In March 2014, we acquired 100% of the interests in Red Rock Gathering Company, LLC ("Red Rock Gathering") from a subsidiary of Summit Investments. Summit Investments acquired the natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin that comprise the Red Rock Gathering system from a subsidiary of Energy Transfer Partners, L.P. in September 2012. These assets gather and process natural gas from the Mesaverde formation and the emerging Mancos and Niobrara shale formations located within the Piceance Basin in western Colorado and eastern Utah. They are primarily located in Rio Blanco and Mesa counties in Colorado and Uintah and Grand counties in Utah. We refer to the assets that we acquired in March 2014 as the Red Rock Gathering, and collectively with the Legacy Grand River system, as the Grand River system. The Grand River system currently provides our midstream services for the Piceance Basin reportable segment.
Natural gas gathered and/or processed on the Grand River system is compressed, dehydrated, processed and/or discharged to downstream pipelines serving (i) Enterprise's Meeker Natural Gas Processing Plant, a 1.8 Bcf/d processing facility located in Meeker, Colorado, (ii) Williams Partners L.P.'s Northwest Pipeline system, and (iii) Kinder Morgan, Inc.'s TransColorado Pipeline system. Processed NGLs from the Grand River system are injected into Enterprise's Mid-America Pipeline system.
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 emerging Mancos and Niobrara shale formations, which underlie the Mesaverde formation, via a new medium-pressure gathering system. Based on our customers' current drilling activities, 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 existing throughput capacity. In addition, we believe that the Grand River system is optimally located for expansion to gather production from the emerging Mancos and Niobrara shale formations.
The following table provides information regarding our Grand River system as of December 31, 2014.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2018 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Grand River	1,780	154,150	1,153	670,960	726	2,143	10.4

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).
In October 2011, we entered into a long-term, fee-based gas gathering agreement with Encana as our anchor customer that included a 25-year AMI covering approximately 187,000 acres and a 15-year MVC totaling approximately 1,558 Bcf. In conjunction with Summit Investments' acquisition of Red Rock Gathering, we assumed fee-based agreements with Black Hills Exploration and Production, Inc. ("Black Hills") and a subsidiary of WPX. Both agreements include long-term acreage dedications and collectively provide more than 375 Bcf of MVCs. Certain of the Grand River system's other gas gathering and processing agreements include MVCs with original terms ranging from from two to 15 years and areas of mutual interest with original terms up to 25 years.
In connection with the Black Hills agreement, we constructed a 20 MMcf/d cryogenic processing plant and related gas gathering infrastructure in the DeBeque, Colorado area to support Black Hills' development of its liquids-rich Mancos and Niobrara acreage. In connection with the WPX agreement, we agreed to expand our gathering and compression services by constructing gas gathering infrastructure to gather new WPX production in the Rifle, Colorado area. The processing plant in DeBeque was commissioned in March 2014 and the WPX project is in process and development is expected to continue over the next few years. We intend to expand the Grand River system by connecting additional pad sites within our areas of mutual interest, adding new customers, and acquiring nearby gathering systems. In

addition to Encana, WPX and Black Hills, the Grand River system is underpinned by other long-term, fee-based gas gathering and compression agreements.

For additional information relating to our business and gathering systems as well as the recent decline in natural gas and crude oil prices and our commodity price exposure, see the "Trends and Outlook—Natural gas, NGL and crude oil supply and demand dynamics" and "Results of Operations" sections in MD&A.

Table of Contents

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. The Federal Energy Regulatory Commission ("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 Federal Trade Commission 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 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 Natural Gas Act 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. We believe that our gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978 (the "NGPA"), although we are subject to FERC's anti-market manipulation regulations. The distinction between federally unregulated gathering facilities and FERC-regulated transmission 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 gathering system may be determined by FERC on a case-by-case basis, although FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of gathering systems (including some of our pipelines) could change based on future determinations by FERC or the courts.

Intrastate pipelines, which may include some pipelines that perform gathering functions, may be subject to safety regulation by the U.S. Department of Transportation 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 a tariff in Colorado for our Grand River system assets, nor have we been required to file a tariff in West Virginia or North Dakota for our operations in those states, although regulatory authorities in North Dakota have recently issued new rules requiring the submission of shape files to identify the location of underground gathering pipelines. 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 Texas, Colorado, North Dakota, and West Virginia 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.

Natural gas 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 Natural Gas Act and the NGPA, as amended by the Energy Policy Act of 2005, which authorize FERC to impose fines of up to

$1,000,000 per day per violation of the Natural Gas Act, the NGPA, or their implementing regulations. In addition, the Federal Trade Commission holds statutory authority under the Energy Independence and Security Act of 2007

Table of Contents

to prevent market manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1,000,000 per violation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The Commodity Futures Trading Commission (the "CFTC") is directed under the Commodity Exchange Act to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,000,000 per day per violation or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the Commodity Exchange Act. 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 U.S. Department of Transportation under the Natural Gas Pipeline Safety Act of 1968, as amended (the “NGPSA”) which establishes federal safety standards for the design, construction, operation and maintenance of natural gas pipeline facilities. In the Pipeline Safety Act of 1992, Congress expanded the U.S. Department of Transportation'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 reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

The U.S. Department of Transportation has delegated the implementation of safety requirements to the Pipeline and Hazardous Materials Safety Administration (the "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 U.S. Department of Transportation regulations for intrastate pipelines. Among the regulations applicable to us, the 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 gathering system is located. While the majority of our pipelines meet the U.S. Department of Transportation definition of gathering lines and are thus exempt from the integrity management requirements of the 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.

The PHMSA has published notices and advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements. The PHMSA has also solicited comments on changes to the definition of gathering pipelines, which could subject many currently exempted pipelines to the PHMSA regulations. The PHMSA also published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. Pipelines that do not meet the PHMSA's record verification standards may be required to perform additional testing or reduce their operating pressures.

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 OSHA hazard communication standard, Environmental Protection Agency ("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.

Table of Contents

Environmental Matters

General. Our operation of pipelines and other assets for the gathering, compressing and dehydration of natural gas and other products 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. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act and comparable state statutes. While the Resource Conservation and Recovery Act 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. These properties and the wastes disposed thereon may be subject to CERCLA, the Resource Conservation and Recovery Act 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 Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring 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 April 2012, the EPA finalized rules that establish new air emission reporting, monitoring, and control requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") from a number of sources that were previously not regulated in the oil and gas industry. Additionally, the EPA revised several existing regulations to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific new requirements regarding emissions from compressors, pneumatic controllers, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants at 500 ppm. These rules required a number of modifications to our operations, including the installation of new equipment to control emissions from VOC emitting tanks at initial startup. To date, compliance with such rules has not resulted in significant costs, but we will continue to evaluate their impact and associated costs.

On December 17, 2014, the EPA proposed to lower the existing national ambient air quality standard (“NAAQS”) for ozone. A 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.

In addition, in February 2014, the Colorado Department of Public Health and Environment’s Air Quality Control Commission finalized regulations imposing stringent new requirements relating to air emissions from oil and gas facilities in Colorado. These new Colorado rules include storage tank control, monitoring, recordkeeping and reporting requirements as well as leak detection and repair requirements for both well production facilities and compressor stations and associated equipment. The new requirements went into effect January 2015.

Water Discharges. The Clean Water Act, 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.

Oil Pollution Act. The Oil Polution Control Act (the "OPA") requires the preparation of a Spill Prevention Control and Countermeasure (“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.

Table of Contents

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 is also moving forward with various related regulatory actions, including approving, on April 17, 2012, new regulations requiring, among other matters, green completions of hydraulically-fractured wells by 2015. We do not believe these new regulations will have a direct effect on our operations, but because oil and/or natural gas 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.

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 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. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews and in March 2012, issued final guidance that may result in longer review processes.

Climate Change. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other 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 has adopted regulations under the Clean Air Act that, among other things, establish GHG emission limits from motor vehicles as well as establish Prevention of Significant Deterioration (“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.

In addition, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emitting sources in the United States beginning in 2011 for emissions in 2010. In November 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. We are required to report under these rules for our assets that have greenhouse gas emissions above the reporting thresholds. The EPA continues to consider additional climate change requirements for the energy industry. Such developments may affect how these greenhouse gas initiatives will impact our operations.

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 greenhouse gas emitting energy sources, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. Conversely, to the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas 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 or its affiliates, 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, 2014, Summit Investments employed 254 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 Securities and Exchange Commission (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,

Table of Contents

www.summitmidstream.com, as soon as reasonably practicable 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.

Risks Related to our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution ("MQD") or any distribution to holders of our common and subordinated units.

To pay the minimum quarterly distribution of $0.40 per unit per quarter, or $1.60 per unit on an annualized basis, we will require available cash of approximately $24.1 million per quarter, or $96.6 million per year (based on units outstanding, as of December 31, 2014, including nonvested SMLP LTIP awards). We may not have sufficient available cash from operating surplus each quarter to pay the minimum quarterly distribution. 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 volume of natural gas we gather, treat and process;
- the level of production of natural gas 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, whether as a result of human error or otherwise;
- weather conditions and seasonal trends;
- changes in the fees we charge for our services;
- the level of competition from other midstream energy companies in our geographic markets;
- 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 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 to our general partner for services provided to us;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

Table of Contents

We depend on our anchor 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 flow and ability to make cash distributions to our unitholders.

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 flow and ability to make cash distributions to our unitholders. Some 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 our key anchor customers could have a material adverse effect on our revenue and cash flows and our ability to make cash distributions to our unitholders. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our revenue.

Adverse developments in our existing 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 natural gas gathering, treating and processing services in four unconventional resource basins: (i) the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia; (ii) the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota; (iii) the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and (iv) the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah. Due to our lack of 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.

In addition, our operations in the Barnett Shale region could expose us to disproportionate operational and regulatory risk in that area. The location of the Barnett Shale in the Dallas-Fort Worth, Texas metropolitan area poses unique challenges associated with drilling for and gathering natural gas in urban and suburban communities. The DFW Midstream system is located within the city limits of various municipalities in that region, including Arlington, Texas. State and local regulations regarding the operation of drilling rigs limit the number of potential new drilling sites that can be used for infill drilling programs, which has led producers to pursue a high-density pad site drilling strategy. Furthermore, the process of obtaining permits for constructing additional gathering lines to deliver our customers' natural gas to market may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

Significant prolonged weaknesses in natural gas, NGL and crude oil prices could affect supply and demand, thereby reducing throughput on our systems and materially adversely affecting our revenues and cash available to make cash distributions to our unitholders over the long term.

The current level of low natural gas, NGL and crude oil prices has had a negative impact on exploration, development and production activity in our areas of operation. Unchanged or lower natural gas, NGL and crude oil prices over the long term could result in a decline in the production of natural gas and crude oil, thereby resulting in reduced throughput on our gathering systems. The price of natural gas has been at historically low levels for an extended period of time. The lower price of natural gas is due in part to increased production, especially from unconventional sources, such as natural gas shale plays, and a warmer winter. Furthermore, the amount of natural gas in storage in the continental United States has generally increased due to the decisions of many producers to store natural gas in the expectation of higher prices in the future as well as decreased demand as a result of unseasonably warm winters. In response to lower natural gas prices, the number of natural gas drilling rigs has declined as a number of producers have curtailed their exploration and production activities. Until the supply overhang has been reduced and the economy sees more robust growth, we believe that natural gas pricing is likely to be constrained. The price of crude oil has recently experienced a significant decline in response to a recent global supply surplus, with OPEC stating in November 2014 that it would not decrease production levels, despite estimates of slowing global demand. Additionally, due to the extended period of historically low natural gas prices and recent decline in NGL and crude oil prices, certain of our customers in each of our areas of operations have, and others could, reduce drilling activity and capital expenditure budgets.

Table of Contents

If natural gas, NGL and/or crude oil prices remain depressed or decrease further, 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.

Because of the natural decline in production from existing wells in our areas of operation, 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 of natural gas that we gather and process could materially adversely affect our business and operating results.

The natural gas volumes that support our business depend on the level of production from natural gas 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 natural gas. The primary factors affecting our ability to obtain new sources of natural gas 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 commodity prices, including the prices of crude oil, natural gas and other hydrocarbon products;
- demand for crude oil, natural gas and other hydrocarbon products;
- 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.

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 conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas ("LNG");
- the ability to export LNG;
- the availability of transportation 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.

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 revenue and cash flow and materially adversely affect our ability to make cash distributions to our unitholders.

Table of Contents

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 operating costs are fixed and do not vary with our throughput. These costs may not decline ratably or at all should we experience a reduction in throughput, which would result in a decline in our revenue and cash flow and materially adversely affect our ability to make cash distributions to our unitholders.

If our customers do not increase the volumes of natural gas 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, our ability to increase the throughput on our gathering systems will be dependent on receiving increased volumes from our existing customers. Other than the scheduled increases in the minimum volume commitments provided for in our gas gathering and processing agreements, 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.

Our gas gathering and processing agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

Our gas gathering and processing agreements were designed to generate stable cash flows for us over the life of the minimum volume commitment contract term while also minimizing direct commodity price risk. Under these minimum volume commitments, our customers agree to ship a minimum volume of natural gas on our gathering systems or to our processing plants or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the minimum volume commitment. In addition, the majority of our gas gathering and processing agreements also include an aggregate minimum volume commitment, which is a total amount of natural gas that the customer must flow on our gathering system or send to our processing plants (or an equivalent monetary amount) over the minimum volume commitment term. If a customer's actual throughput volumes are less than its minimum volume commitment for the applicable period, it must make a shortfall payment to us at the end of that contract month, quarter or year, as applicable. 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 minimum volume commitment for the applicable period, multiplied by the applicable fee. To the extent that a customer's actual throughput volumes are above or below its minimum volume commitment for the applicable period, many of our gas 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.

Under certain circumstances, it is possible that the combined effect of the minimum volume commitment provisions could result in our receiving no revenues or cash flows from one or more customers in a given period. In the most extreme circumstances:

- we could incur operating expenses with no corresponding revenues from one or more significant customers for a period of up to 35 months; or
- all or a substantial portion of our customers could cease shipping throughput volumes at a time when their respective aggregate minimum volume commitments have been satisfied with previous throughput volume shipments.

If either of these circumstances were to occur, it would 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 do not intend to obtain independent evaluations of natural gas reserves connected to our gathering systems on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We have not obtained and do not intend to obtain independent evaluations of the natural gas reserves connected to our systems on a regular or ongoing basis. Moreover, even if we did obtain independent evaluations of the natural

Table of Contents

gas 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 some or all of 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 sources of natural gas, 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 operation. Some of our competitors are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors have assets in closer proximity to natural gas supplies and 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 and produce natural gas may choose to use one of our competitors to gather and process that natural gas.

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 revenue and cash flow could be materially adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

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

We gather, treat and process the natural gas on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and 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 to our markets;
- the macroeconomic factors affecting natural gas gathering 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 markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

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.

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 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.

18

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 or have limited financial resources 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 might have an impact on many of our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us and may also increase the magnitude of these obligations.

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

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

Our natural gas gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, owned and operated by unaffiliated third parties. 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 because of 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 operational 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 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 that we gather and process, our revenue, cash flow and ability to make cash distributions to our unitholders could be materially adversely affected.

We have a limited ownership history with respect to all 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.

Our executive management team has a relatively limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems of which our executive management team may be unaware and that may have a material adverse effect on our business and results of operations. The steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures over time to connect additional wells and maintain throughput volume. 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.

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

The gathering, treating and processing of natural gas 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.

Crude oil and natural gas activities in certain areas of our gathering systems may be adversely affected by seasonal weather conditions 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 across our systems, especially in North Dakota and West Virginia, can be severe and can adversely affect oil and gas operations due to the potential shut-in of producing wells or decreased drilling activities. The result of these types of interruptions could result in a decrease in the volumes of natural gas supplied to our gathering systems. Further, delays and

19

Table of Contents

shutdowns caused by severe weather during the winter months may have a material negative impact on the continuous operations of our gathering systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet contractual obligations to our customers and thereby give rise to certain termination rights and releases of dedicated acreage. Any resulting terminations or releases could materially affect our business and results of operations.

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 gather, treat or process natural gas or NGLs, would adversely affect our operations and cash flows available for distribution to our unitholders.

Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

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

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents 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 gathering, treating and processing of natural gas, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of 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 segments of our systems. Potential customer impacts arising from service interruptions on segments of our systems could include limitations on our ability to satisfy customer requirements, obligations to temporarily waive minimum volume commitments during times of constrained capacity, 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.

Table of Contents

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 accident 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. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, with regard to the assets we have acquired, we have limited indemnification rights to recover 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 Summit Investments, its affiliates or 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 is based, in large part, on our expectation of ongoing divestitures of midstream energy 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 Summit Investments, its affiliates or 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. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue 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;
- an inability to integrate successfully 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 equity or debt;
- 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;
- production declines higher than anticipated; and
- facilities being properly constructed.

If we consummate any future acquisitions, our capitalization and results of operations 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.

Table of Contents

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 diversify the geographic areas in which we operate or 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 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 could be negatively impacted.

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

One of the ways we intend to grow our business is through organic growth projects. 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 may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenue may not increase immediately upon the expenditure of funds on a particular project.

Moreover, we could construct facilities to capture anticipated future growth in production in a region in which 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 new rights-of-way or federal and state 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 rights-of-way or other authorizations and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or authorizations or to renew existing rights-of-way or authorizations. If the cost of renewing or obtaining new rights-of-way or 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 gas gathering and processing agreements. Tightened 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 gas gathering and processing agreements also require us to spend significant amounts of capital, including 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 amended and restated revolving credit facility.

Table of Contents

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 our financial condition at the time of any such financing or offering as well as covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. If we are unable to raise expansion capital, we may lose the opportunity to make acquisitions or to gather, treat and process new natural gas production from our customers with whom we have agreed to construct and develop midstream assets in the future. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional units representing limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

We do not have any commitment from our Sponsor or its affiliates to provide any direct or indirect financial assistance to us.

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 at or near historic lows and may increase in the future. 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 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, 2014, we had $808.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated revolving credit facility totaled $492.0 million. Our future level of debt could have significant consequences, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be limited or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and cash distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

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.

Restrictions in our amended and restated 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 flow 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 amended and restated revolving credit facility, our 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

Table of Contents

may, in turn, limit our ability to make cash distributions to our unitholders. For example, our amended and restated revolving credit facility and indentures 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;
- 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 amended and restated revolving credit facility and 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 amended and restated revolving credit facility and indentures may affect our ability to obtain future financing and pursue attractive business opportunities as well as affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our amended and restated revolving credit facility or indentures could result in a default or an event of default that could enable our lenders or 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 amended and restated 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 amended and restated revolving credit facility also has cross default provisions that apply to any other indebtedness we may have and the indentures have cross default provisions that apply to certain other indebtedness.

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

We generate a substantial majority of our revenues pursuant to long-term, primarily fee-based gas gathering and processing agreements under which we are paid based on the volumes of natural gas that we gather and/or process rather than the value of the underlying natural gas. Consequently, our existing operations and cash flows have limited direct exposure to commodity price risk. Although we will seek to enter into similar fee-based contracts with new customers in the future, our efforts to obtain such contractual terms may not be successful or the local market for our services may not support fee-based gas gathering and processing agreements. For example, in connection with our acquisition of Red Rock Gathering and Bison Midstream, we have percent-of-proceeds and keep-whole contracts with certain customers and we may, in the future, enter into additional percent-of-proceeds and keep-whole contracts with our customers, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of natural gas and natural gas liquids. Under these keep-whole arrangements, our principal cost is delivering dry gas of an equivalent BTU content to replace BTUs extracted from the gas stream in the form of NGLs or consumed as fuel during processing. Generally, the spreads between the NGL product sales price and the purchase price of natural gas with an equivalent BTU content are positive under these arrangements. However, in the event natural gas becomes more expensive on a BTU equivalent basis than NGL products, the cost of keeping the producer “whole” could result in lower, and in some cases, negative, net operating margins.

Substantially all of our remaining revenue is derived from (i) the sale of physical natural gas that we retain from our DFW Midstream customers to offset our power expense associated with our electric-drive compression and (ii) the sale of condensate volumes that we retain on the Grand River system. The revenues we earn from the sale of retained natural gas are tied to the price of natural gas. In addition, changes in the price of crude oil could directly affect the revenues we receive from the sale of condensate.

Furthermore, we may acquire or develop additional midstream assets in the future, including assets related to commodities other than natural gas, that have a greater exposure to fluctuations in commodity price risk than our current operations. Future exposure to the volatility of crude oil and natural gas prices could have a material adverse effect on our business, results of operations and financial condition.

Table of Contents

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 revenue to decline or our operation and maintenance expenses to increase.

Various aspects of our operations are subject to extensive regulation. Numerous federal, state and local departments and agencies are authorized by statute to issue, and have issued, rules, regulations and interpretations binding upon participants in the natural gas industry. The regulation of our activities and the natural gas industry frequently changes as the activities of the industry often are reviewed by legislators and regulators. In 2014, the North Dakota Industrial Commission began to oversee the integrity and location of underground gathering pipelines that are not monitored by other state or federal agencies. The U.S. Department of Transportation (the "DOT") is considering rule changes that would extend pipeline safety regulation to previously unregulated rural gathering systems and increase safety requirements for other pipelines as well. Penalties for violating federal safety standards have recently increased. In addition, the adoption of proposals for more stringent legislation, regulation or taxation of natural gas 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 natural gas production by our customers, 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 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 is also moving forward with various related regulatory actions, including approving, on April 17, 2012, new regulations requiring, among other matters, green completions of hydraulically-fractured wells by 2015. We do not believe these new regulations will have a direct effect on our operations, but because oil and/or natural gas 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, which could adversely affect our results of operations and financial condition.

We are subject to 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 pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC, the NGA and the NGPA. We are, however, 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 $1,000,000 per day per violation of the NGA or its implementing regulations. In addition, the Federal Trade Commission 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 Federal Trade Commission is also authorized to seek fines of up to $1,000,000 per violation. The CFTC is directed under the Commodity Exchange Act, to prevent price manipulation in the commodity, futures and swaps markets, including the energy markets. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, also known as 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 $1,000,000 per violation or triple the monetary gain to the violator for each violation of the anti-market manipulation provisions of the Commodity Exchange Act.

The distinction between federally unregulated gathering facilities and FERC-regulated transmission 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 gas gathering operations become subject to FERC jurisdiction over interstate service under the NGA or the NGPA, the result may

Table of Contents

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 or the NGPA, 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 the FERC.

We are subject to state and local regulation regarding the construction and operation of our gathering 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 gas we may gather, treat and process. Ratable take statutes and regulations generally require gatherers to take natural gas 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 for gathering, treating and processing, including state regulation of production rates, maximum daily production allowable from natural gas 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 natural gas gathering, treating and processing operations are subject to stringent and complex federal, state and local environmental laws and regulations, including laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection, including, for example, the Clean Air Act, Comprehensive Environmental Response, Compensation, and Liability Act, Clean Water Act, Oil Pollution Act, Resource Conservation and Recovery Act, Endangered Species Act, and 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. 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.

Table of Contents

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

The DOT, through its 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, the 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 exempt from the 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.

The PHMSA is considering changes to its safety regulations, including whether to revise the integrity management requirements and whether to change the definition of gathering pipelines, which could subject many currently exempted pipelines to PHMSA regulations and could have a material adverse effect on our operations and costs of transportation services. The PHMSA has also issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity of our pipelines. 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 natural gas services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of greenhouse gases, 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 greenhouse gas emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address greenhouse gas emissions, primarily through the planned development of emission inventories or regional greenhouse gas 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 greenhouse gas emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for greenhouse gas 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 greenhouse gas emissions, such as electric power plants, it is possible that our sources, such as our gas-fired compressors, could become subject to state-level greenhouse gas-related regulation.

Independent of Congress, the EPA has begun to adopt regulations under its existing Clean Air Act 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. In addition,

Table of Contents

in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large greenhouse gas emitting sources in the United States beginning in 2011 for emissions in 2010. In November 2010, the EPA published a final rule expanding the reporting requirement to include onshore and offshore crude oil and natural gas systems beginning in 2012. These rules require that we report our GHG emissions for certain of our assets. 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 greenhouse gas emissions could require us to incur increased operating costs and could materially adversely affect demand for the natural gas we gather, treat or process in connection with our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas 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 natural gas, resulting in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The adoption and implementation of new 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, or OTC, 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, the clearing of certain swaps through central counterparties, the execution of certain swaps on designated contract markets or swap execution facilities, and the reporting and recordkeeping of swaps. While many of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

The CFTC has previously established position limits on certain core futures and equivalent swaps contracts in the major energy, including natural gas, and other markets, with exceptions for certain bona fide hedging transactions provided that various conditions are satisfied. Once finalized, the position limits rule and its companion rule on aggregation 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. Although we may qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered into to hedge commercial risks, mandatory clearing and trade execution requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulatory authorities may require our counterparties to require that we enter into credit support documentation and/or post margin as collateral; however, the proposed margin rules are not yet final and therefore the application of those rules to us is uncertain at this time.

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.

To further define the term “swap,” the CFTC has issued several interpretations clarifying whether certain forwards with optionality will remain as forwards or would qualify as options on commodities and therefore swaps. Once finalized, this interpretation may have an impact on our ability to enter into certain forwards.

Table of Contents

We currently receive a fuel retainage fee from certain of our customers that is paid in-kind to offset the costs we incur to operate our electric-drive compression assets in the Barnett Shale. We currently enter into forward contracts with third parties to buy power and sell natural gas in an attempt to hedge our exposure to fluctuations in the price of natural gas with respect to those volumes. The impact of the Dodd-Frank Act on our hedging activities is uncertain at this time. However, the new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce 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 Dodd-Frank Act may also materially affect our customers and materially and adversely affect the demand for our services.

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 our 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 difficult to satisfy our regulatory obligations. Ongoing litigation regarding the scope of the cross-border rules also creates further uncertainty as to the application of the rules in the cross-border context.

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.

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 in order to prevent or remediate any such attacks.

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 natural gas industry experience and competition for these persons in the midstream natural gas 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

Table of Contents

retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

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 accounting principles generally accepted in the United States of America. 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.

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 as well as 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 will also be 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 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.

- 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 and the ability of the subordinated units to convert to common units.
- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- 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 subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights.
- 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 incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our other unitholders in certain situations.

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.

Energy Capital Partners has significantly greater resources than us and has experience making investments in midstream energy businesses. Energy Capital Partners may compete with us for investment opportunities and may own interests in entities that compete with us. Energy Capital Partners is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Energy Capital Partners 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. While Summit Investments has indicated that it intends to offer us the opportunity to acquire its interests in its midstream assets, it is not under any contractual obligation to do so and we are unable to predict whether or when such opportunities may arise.

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 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.

31

Table of Contents

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow 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 flow 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 record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting 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.

There were 29,132,942 publicly held common units at December 31, 2014. In addition, a subsidiary of Summit Investments, which controls our general partner, owned 5,293,571 common and 24,409,850 subordinated units. An investor may not be able to resell its common units at or above its acquisition price. Additionally, a lack of 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 us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these Risk Factors.

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 of the board of directors of our general partner;
- 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 incentive distribution rights 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 of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

(ii) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

(iii) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(iv) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

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

Our general partner intends to limit its liability regarding our obligations.

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

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

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our

33

Table of Contents

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 or our amended and restated revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

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 generally may not be amended during the subordination period without the approval of our public common unitholders. However, 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) after the subordination period has ended. As of December 31, 2014, a subsidiary of Summit Investments, which owns and controls our general partner, owned 5,293,571 common units and 24,409,850 subordinated units.

Reimbursements due to our general partner and its affiliates for services provided to us or 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 administrative costs, such as compensation expense for those persons 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 and payment of fees, if any, 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 minimum quarterly distribution and the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner's board 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 there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) 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 minimum quarterly distribution 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 minimum quarterly distribution), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

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 incentive distribution rights 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

Table of Contents

expect to experience, declines in the cash distributions it receives related to its incentive distribution rights 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 incentive distribution rights.

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 will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner will be chosen by Summit Investments. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of 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 cannot initially remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. 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, 2014, Summit Investments, which controls our general partner, indirectly owned 5,293,571 common units out of 34,426,513 outstanding common units and all of our 24,409,850 subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would materially adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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.

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

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of 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 new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own 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.

Table of Contents

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.
Our general partner may transfer the incentive distribution rights it owns to a third party at any time without the consent of our unitholders. If our general partner transfers the incentive distribution rights 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 incentive distribution rights. For example, a transfer of the incentive distribution rights by our general partner could reduce the likelihood of Summit Investments selling or contributing additional midstream assets to us, as Summit Investments would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.
We may issue additional units without unitholder approval, which would dilute existing ownership interests.
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. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per-unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Summit Investments 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, 2014, a subsidiary of Summit Investments held an aggregate of 5,293,571 common units and 24,409,850 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period. In addition, we have agreed to provide this affiliate with certain registration rights. The sale 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, 2014, Summit Investments owned 5,293,571 common units and 24,409,850 subordinated units. At the end of the subordination period, assuming no acquisitions, dispositions, retirement or additional issuance of common units (other than upon the conversion of the subordinated units), Summit Investments will own 29,703,421 common units, or approximately 50.5% of our then-outstanding common units.
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

Table of Contents

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.

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 and subordinated 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 and 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.

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.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service (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 common 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 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 a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of

Table of Contents

our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to 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 reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

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 minimum quarterly distribution 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 common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, 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. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if the unitholder receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take, 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 the positions we take and such positions may not ultimately be sustained. Any contest with the IRS, and the outcome of any IRS contest, may have an adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

If a unitholder sells its common 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 common units. Because distributions in excess of a unitholder's allocable share of its net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units the it sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than the its tax basis in those common units, even if the price it receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale of a unitholder's common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its common 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 common units that may result in adverse tax consequences to them.

Investment in common 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 organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. 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. It also could affect the timing of these tax benefits or the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction for 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 will prorate our items of income, gain, loss and deduction for 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 use of this proration method may not be permitted under existing Treasury regulations. Recently, however, the U.S. Treasury Department issued proposed regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a short seller to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common 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 common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are advised 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 common units.

We adopted certain valuation methodologies and monthly conventions for 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 the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our

Table of Contents

unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.
A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.
The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.
We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and would result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.
As a result of investing in our common units, our unitholders may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.
In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if the unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. Some of the states in which we conduct business currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is the unitholder's responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments.
Not applicable.

Item 2. Properties.
We currently have four natural gas gathering systems which provide gathering, treating and processing services. They are (i) the Mountaineer Midstream system located in Doddridge and Harrison counties, West Virginia, (ii) the Bison Midstream system located in Mountrail and Burke counties, North Dakota, (iii) the DFW Midstream system located primarily in Tarrant County, Texas and (iv) the Grand River system located primarily in Garfield, Mesa and Rio

Blanco counties, Colorado and Uintah and Grand counties, Utah. For additional information on our gathering systems and their capacities, see Item 1. Business.

Table of Contents

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our gathering systems and other major facilities are located are owned by us in fee title, and we believe that we have valid title to these lands. The remainder of the land on which our major facilities are located are held by us pursuant to long-term leases or easements between us and the underlying fee owner, or permits with governmental authorities. Our Predecessor leased or owned these lands without any material challenge known to us relating to the title to the land upon which our assets are located, and 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, and we have additional regional corporate offices in Denver, Colorado and Atlanta, Georgia.

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. 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 January 2015, the U.S. Department of Justice issued a grand jury subpoena to Summit Investments, the Partnership and our general partner requesting certain materials related to an incident involving a produced water disposal pipeline owned by Meadowlark Midstream Company, LLC (“Meadowlark”) that resulted in a discharge of materials into the environment. Meadowlark is an indirect, wholly owned subsidiary of Summit Investments. The Partnership and our general partner do not currently have, nor have they ever had, any management or operational control over, or ownership interest in, Meadowlark or the pipeline. As a result, 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 trade on the New York Stock Exchange. Our ticker symbol is "SMLP." As of February 17, 2015, there were approximately 9,250 common unitholders, including beneficial owners of common units held in street name. There is one record holder of our subordinated units. There is no established public trading market for our subordinated units.

The following table shows the high and low price per common unit, as reported by the New York Stock Exchange for the periods indicated.

	Common unit price range		Cash distribution paid per common unit
	High	Low	
4th Quarter 2014	$51.44	$32.30	$0.54
3rd Quarter 2014	$56.49	$46.50	$0.52
2nd Quarter 2014	$51.25	$40.53	$0.50
1st Quarter 2014	$43.98	$34.72	$0.48
4th Quarter 2013	$38.20	$30.66	$0.46
3rd Quarter 2013	$35.40	$31.62	$0.435
2nd Quarter 2013	$35.40	$26.04	$0.42
1st Quarter 2013	$28.50	$18.67	$0.41

On January 22, 2015, the board of directors of our general partner declared a distribution of $0.56 per unit for the quarterly period ended December 31, 2014. The distribution, which totaled approximately $35.1 million, was paid on February 13, 2015 to unitholders of record at the close of business on February 6, 2015.

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. For additional information, see Note 8 to the audited 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:

- Our cash distribution policy is subject to restrictions on distributions under our amended and restated revolving credit facility. Our amended and restated 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 you 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.

Table of Contents

- 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. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders other than in certain limited circumstances where no unitholder approval is required. However, 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 directly and indirectly by Summit Investments) after the subordination period has ended. As of December 31, 2014, a subsidiary of Summit Investments owned our general partner as well as 5,293,571 common units and all of our 24,409,850 subordinated units.
- 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. We will 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 will 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 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner's initial 2.0% 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 2.0% general partner interest.

The following table sets forth the aggregate quarterly and annual MQD (including distribution equivalent rights) based on all of the units outstanding as of December 31, 2014 (including unvested awards under the 2012 SMLP Long Term Incentive Plan, or "SMLP LTIP").

	Minimum Quarterly Distribution		
	Number of units	Per quarter	Annualized
	(Dollars in thousands)		
Publicly held common units	29,132,942	$11,653	$46,613
Common units held by a subsidiary of Summit Investments	5,293,571	2,117	8,470
Subordinated units held by a subsidiary of Summit Investments	24,409,850	9,764	39,056
2.0% general partner interest	1,200,651	480	1,921
Total units outstanding	60,037,014	24,014	96,060
SMLP LTIP participant phantom units(1)	336,202	134	538
Total outstanding and unvested units	60,373,216	$24,148	$96,598

(1) Represents distribution equivalent rights on awards of phantom units not yet vested.

For additional information, see Note 8 to the audited consolidated financial statements.

Table of Contents

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 50 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, 2014.

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 December 31, 2014, 2013, 2012, 2011, and 2010 and for the years ended December 31, 2014, 2013, 2012, 2011, and 2010 have been derived from the audited consolidated financial statements of SMLP and its Predecessor.

SMLP completed its IPO on October 3, 2012. For the year ended December 31, 2012, these financial statements include the Predecessor's results of operations through the date of SMLP's IPO.

These financial statements reflect the results of operations of (i) Bison Midstream since February 16, 2013, (ii) Mountaineer Midstream since June 22, 2013, (iii) Red Rock Gathering since October 23, 2012 and (iv) Grand River Gathering since October 27, 2011. SMLP recognized its acquisitions of Bison Midstream (the "Bison Drop Down") and Red Rock Gathering (the "Red Rock Drop Down") at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment in Bison Midstream over the purchase price paid by SMLP was recognized as an addition to partners' capital. The excess of the purchase price paid by SMLP over Summit Investments' net investment in Red Rock Gathering was recognized as a reduction to partners' capital. Due to the common control aspect, the Bison Drop Down and the Red Rock Drop Down were accounted for by the Partnership on an "as-if pooled" basis for the periods during which common control existed.

Table of Contents

Due to the various asset acquisitions and the associated shift in business strategies relative to those of our Predecessor, SMLP's financial position and results of operations may not be comparable to the historical financial position and results of operations of the Predecessor.

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

	December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per-unit amounts)				
Balance sheet data:					
Total assets	$1,894,874	$1,883,739	$1,280,939	$1,030,264	$340,095
Total long-term debt	808,000	586,000	199,230	349,893	—
Partners' capital	966,889	1,201,737	1,030,248	n/a	n/a
Membership interests	n/a	n/a	n/a	640,818	307,370
Other data:					
Market price per common unit	$38.00	$36.65	$19.83	n/a	n/a

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n/a - Not applicable

The following table presents selected statement of operations data by entity for the periods indicated.

	Year ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per-unit amounts)				
Statement of operations data:					
Total revenues	$330,686	$292,920	$174,423	$103,552	$31,676
Total costs and expenses	312,249	219,719	117,987	61,864	23,412
Interest expense	40,159	19,173	7,340	1,029	—
Affiliated interest expense	—	—	5,426	2,025	—
Net (loss) income	(21,164)	53,304	42,997	37,951	8,172
Earnings per limited partner unit:					
Common unit – basic	$(0.49)	$0.86	$0.35	n/a	n/a
Common unit – diluted	(0.49)	0.86	0.35	n/a	n/a
Subordinated unit – basic and diluted	(0.44)	0.79	0.35	n/a	n/a
Other financial data:					
EBITDA	$103,556	$144,195	$93,302	$53,363	$12,353
Adjusted EBITDA	193,778	164,839	105,946	56,803	12,353
Capital expenditures	128,325	109,376	77,296	78,248	153,719
Acquisition capital expenditures (1)	315,872	458,914	—	589,462	—
Distributable cash flow	139,611	128,141	90,947	50,980	11,726
Distributions declared per unit (2)	2.120	1.795	0.410	n/a	n/a

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n/a - Not applicable

(1) Reflects cash paid and value of units issued, if any, to fund our acquisitions of the Red Rock Gathering system in 2014 and the Bison Midstream and Mountaineer Midstream systems in 2013, and our Predecessor's acquisition of the Grand River Gathering system in 2011.

Table of Contents

(2) Represents distributions declared in respect of a given quarterly period. For example, in 2014, represents the distributions declared in April 2014 for the first quarter of 2014, July 2014 for the second quarter of 2014, October 2014 for the third quarter of 2014 and January 2015 for the fourth quarter of 2014.

For a detailed discussion of the data presented above, including information regarding our use of EBITDA, adjusted EBITDA and distributable cash flow as well as their reconciliations to net income and net cash flows provided by operating activities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. The preceding tables should also be read in conjunction with the audited consolidated financial statements and related notes.

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

This 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 audited consolidated financial statements and notes thereto included in this report. Among other things, those 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 on page ii of this Annual Report on Form 10-K. Actual results may differ materially from those contained in any forward-looking statements.

Item 7. MD&A is divided into the following sections:

- Overview
- Trends and Outlook
- How We Evaluate Our Operations
- Results of Operations
- Non-GAAP Financial Measures
- Liquidity and Capital Resources
- Critical Accounting Estimates

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 North America. We gather, treat and process natural gas from both dry gas and liquids-rich regions. Dry gas regions contain natural gas reserves that are primarily composed of methane. Liquids-rich regions include natural gas reserves that contain natural gas liquids, or NGLs, in addition to methane.

We currently operate natural gas gathering systems in four unconventional resource basins:

- the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

We believe that our gathering systems are well positioned to capture volumes from producer activity in these regions in the future.

Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. We contract with producers to gather natural gas from pad sites and central receipt points connected to our systems, which we then compress, dehydrate, and/or treat for delivery to downstream pipelines for ultimate delivery to our or third-party processing plants and/or end users.

Table of Contents

We generate the majority of our revenue from the natural gas gathering, treating and processing services that we provide to our natural gas producer customers under primarily long-term and fee-based natural gas gathering and processing agreements. Under these agreements, we are paid a fixed fee based on the volume of the natural gas we gather, treat and/or process. These agreements enhance the stability of our cash flows by providing a revenue stream that is not subject to direct commodity price risk. We also earn revenue from our marketing of natural gas and natural gas liquids and from the sale of physical natural gas purchased from our customers under percentage-of-proceeds and keep-whole arrangements, which can expose us to commodity price risk. We sell condensate retained from our gathering services at Grand River Gathering.

We have indirect exposure to changes in commodity prices in that persistent low commodity prices may cause our customers to delay drilling or temporarily shut in production, which would reduce the volumes of natural gas that we gather. If our customers delay drilling or temporarily shut-in production, our MVCs ensure that we will receive a certain amount of revenue from our customers.

Most of our gas gathering agreements are underpinned by AMIs and MVCs. Our AMIs cover over 1.4 million acres in the aggregate and provide that any natural gas produced from wells drilled by our customers within the AMI will be shipped on our gathering systems. Our MVCs, which totaled 3.8 Tcf at December 31, 2014 and average approximately 1,248 MMcf/d through 2018, are designed to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gas gathering agreement, whether by collecting gathering fees on actual throughput or from cash payments to cover any minimum volume commitment shortfall. Our MVCs had a weighted-average remaining life of 9.7 years as of December 31, 2014, assuming minimum throughput volumes for the remainder of the term.

For additional information on our gathering systems, see Item 1. Business and "Results of Operations—Combined Overview" below.

Trends and Outlook

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

- Acquisitions from Summit Investments and third parties;
- Natural gas, NGL and crude oil supply and demand dynamics;
- Growth in 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.

Acquisitions from Summit Investments and third parties. 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 make acquisitions that increase the amount of cash generated from our operations on a per-unit basis, along with other factors. We pursue accretive acquisitions of midstream assets from Summit Investments and third parties. For example, in 2013, we acquired Bison Midstream from a subsidiary of Summit Investments and Mountaineer Midstream from an affiliate of MarkWest, and, in 2014, we acquired Red Rock Gathering from a subsidiary of Summit Investments.

Summit Investments currently owns and operates, and continuously seeks to acquire and develop, crude oil, natural gas and water-related midstream assets that are both in service and under construction in geographic areas in which we currently operate, as well as in geographic areas outside of our current areas of operations. Summit Investments has invested and expects to continue to invest an aggregate of more than $2.3 billion over the next several years to further develop its portfolio of crude oil, natural gas, and water-related midstream energy infrastructure assets in the Bakken Shale in North Dakota, the DJ Niobrara Shale in Colorado and the Utica Shale in southeastern Ohio.

The acquisition component of our principal business strategy, including future acquisitions from Summit Investments, has required and will continue to require significant expenditures by us and access to external sources of financing from the debt and equity capital markets. Furthermore, as our Sponsor and its affiliates are under no obligation to provide any direct or indirect financial assistance to us, we rely primarily on external financing sources,

Table of Contents

including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Any prospective transaction would be impacted by our ability to obtain financing on acceptable terms from the capital markets or other sources, among other factors.

Given the size of Summit Investments' midstream asset portfolio and the expected additional investment that it intends to make to sufficiently develop those midstream assets, we expect to have the opportunity to make significant additional acquisitions from Summit Investments. Based on current expectations, we are estimating drop down transactions from Summit Investments or its subsidiaries in the range of $400.0 million to $800.0 million, annually through 2017. However, Summit Investments or its subsidiaries have no obligation to offer any assets to us in the future and we have no obligation to acquire any assets that are offered to us. Moreover, there are a number of risks and uncertainties that could cause our current expectations and projections to change, including, but not limited to, (i) Summit Investments deciding, in its sole discretion, to offer us the right to acquire the assets; (ii) the ability to reach agreement on acceptable terms; (iii) the approval of the conflicts committee of our general partner's board of directors (if appropriate); (iv) prevailing conditions and outlook in the crude oil, natural gas and natural gas liquids industries and markets; and (v) our ability to obtain financing on acceptable terms from the capital markets or other sources. For a more extensive list of these risks and uncertainties, see "Risks Related to Our Business—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 Summit Investments, its affiliates or third parties, our future growth will be affected, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations." in Item 1A. Risk Factors.

We also continue to actively pursue third-party acquisitions. However, their size, timing and/or contribution to our results of operations cannot be reasonably estimated.

We expect to fund potential drop downs and acquisitions with equity offerings and borrowings under our revolving credit facility, initially. Longer-term financing is expected to be provided by the issuance of additional debt and equity securities. In each of 2014 and 2013, we accessed the bond markets for $300.0 million to fund portions of our acquisitions and to pay down a portion of our revolving credit facility. We also issued equity securities in 2014 to fund a portion of the Red Rock Drop Down and in 2013, we issued equity securities to a subsidiary of Summit Investments to fund portions of the Bison Drop Down and the Mountaineer Midstream acquisition. See the "Liquidity and Capital Resources—Capital Requirements" section herein and Notes 7 and 8 to the audited consolidated financial statements for additional information.

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. Recently, the price of natural gas has decreased, with the New York Mercantile Exchange, or NYMEX, natural gas futures price at $2.89 per MMBtu as of December 31, 2014 compared with $4.23 per MMBtu as of December 31, 2013. Lower prices in 2014 relative to 2013 are primarily attributable to a milder-than-expected winter, which resulted in lower-than-normal overall consumption of natural gas. As a result, the amount of natural gas in storage in the continental United States increased to approximately 3.2 Tcf as of December 26, 2014 from approximately 3.0 Tcf as of December 27, 2013, compared with a ten-year historical December average of 3.3 Tcf.

Current natural gas prices continue to be lower than historical prices due in part to increased production, especially from unconventional sources, such as natural gas shale plays. According to the U.S. Energy Information Administration (the "EIA"), average annual natural gas production in the United States increased to 66.7 Bcf/d, or 21.1%, in 2013 from 55.1 Bcf/d in 2008. Over the same time period, natural gas consumption increased only 12.3% to 71.6 Bcf/d. In response to lower natural gas prices, the number of natural gas drilling rigs has declined from approximately 1,350 in December 2008 to approximately 340 in December 2014, according to Baker Hughes. We believe that over the near term, until the supply of natural gas has been reduced or the broader economy experiences more robust growth, natural gas prices are likely to be constrained.

Over the long term, we believe that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation. For example, according to the EIA, coal-fired power plants generated 39% of the electricity in the United States in 2013, compared with 48% in 2008. In April 2014, the EIA projected total annual domestic consumption of natural gas to increase from approximately 70.0 Bcf/d in 2012 to approximately 86.4 Bcf/d in 2040. Consistent with the rise in consumption, the EIA projects that total domestic natural gas production will continue to grow through 2040 to 102.8 Bcf/d. The EIA also projects the United States to be a net exporter of liquefied natural gas, or LNG, by 2018, with net U.S. exports of LNG projected to rise to 15.8 Bcf/d in 2040 from a 2013 net imported amount of 4.1 Bcf/d. We believe that increasing consumption of natural gas will continue to drive natural gas drilling and production over the long term throughout the United States.

Table of Contents

In addition, the Bison Midstream system is directly affected by crude oil supply and demand dynamics. Crude oil has been the focus of a recent global supply surplus, with OPEC stating in November 2014 that it would not decrease production levels, despite estimates of slowing global demand, particularly in historically high growth countries such as China. This, in conjunction with continued crude oil production growth in the United States, has played a significant role in the recent decline in crude oil prices, with NYMEX crude oil futures ending 2014 at $53.27 per barrel, compared to a high in June 2014 of $107.26 per barrel. For additional information, see the "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" section herein and Notes 4 and 5 to the audited consolidated financial statements.

Over the next two years, the EIA projects that domestic crude oil production will continue to increase from an average of 8.6 million Bbl/d in 2014 to 9.5 million Bbl/d in 2016. While long-term estimates vary due to uncertainty regarding long-term crude oil price trends, the EIA still sees continued growth in certain unconventional shale plays, with crude oil prices expected to remain high enough to support continued drilling and increasing production in the Bakken Shale, Eagle Ford Shale, Permian Basin, and Niobrara Shale.

In addition to the influence that crude oil market dynamics have on our Bison Midstream system, they produce a secondary effect on the natural gas market as a whole. According to the EIA, of the 82.2 Bcf/d of natural gas that was produced in 2013, 14.9 Bcf/d, or 18%, was related to associated natural gas produced from crude oil wells. Effectively, a decrease in production from these types of wells could play a part in increasing natural gas prices.

Growth in production from U.S. shale plays. Over the past several years, a fundamental shift in production has emerged with the growth of natural gas production from unconventional resources. While the EIA expects total domestic natural gas production to grow from 24.1 Tcf in 2013 to 37.6 Tcf in 2040, it expects shale gas production to grow to 19.8 Tcf in 2040, representing 53% of total U.S. natural gas production. Most of this increase is due to the emergence of unconventional natural gas plays and advances in technology that have allowed producers to extract significant volumes of natural gas from these plays at cost-advantaged per-unit economics when compared to most conventional plays.

In recent years, producers have leased large acreage positions in the areas in which we operate and other unconventional resource plays. To help fund their drilling programs in many of these areas, a number of producers have entered into joint venture arrangements with large international operators, industrial manufacturers and private equity sponsors. These producers and their joint venture partners have committed significant capital to the development of the Piceance Basin and the Barnett, Bakken and Marcellus shale plays and other unconventional resource plays, which we believe will support sustained drilling activity.

As a result of the current low commodity price environment, many producers have announced reductions to their capital expenditure budgets by limiting their drilling activities in lower performing resource plays or in lower tier areas within higher performing resource plays. Nevertheless, we believe producers will remain focused on deploying capital in their highest quality resource plays, even in a low commodity price environment.

Capital markets activity and cost of capital. The credit markets have continued to experience near-record lows in interest rates. As oil prices begin to stabilize and the overall economy strengthens, it is likely that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. This 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 competitors would face similar circumstances.

Shifts in operating costs and inflation. During most of 2014, 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 and equipment. An increase in the general level of goods and services in the broader economy could have a similar effect. In a highly competitive scenario, we attempt to recover increased costs from our customers, but there may be a delay in doing so or we may be unable to recover all of these costs. To the extent we are unable to procure necessary supplies or recover higher costs, our operating results will be negatively impacted.

How We Evaluate Our Operations

We conduct our operations in the midstream sector through four reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;

Table of Contents

- the Williston Basin, which is served by Bison Midstream;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River. Grand River is composed of the Legacy Grand River and Red Rock gathering systems.

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 review these measurements on a regular basis for consistency and trend analysis. These metrics include:

- throughput volume,
- revenues,
- operation and maintenance expenses,
- EBITDA,
- adjusted EBITDA and segment adjusted EBITDA, and
- distributable cash flow.

Throughput Volume

The volume of natural gas that we gather, treat and process 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 natural gas 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 natural gas is impacted by:

- successful drilling activity within our areas of mutual interest;
- 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 areas of mutual interest awaiting connections;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing areas of mutual interest; and
- our ability to gather, treat and process natural gas that has been released from commitments with our competitors.

Revenues

Our revenues are primarily attributable to the volume of natural gas that we gather, treat and 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 and keep-whole 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 natural gas gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of natural gas on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. These MVCs 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.

Table of Contents

The majority of the compressors on our DFW Midstream system are electric driven and power costs are directly correlated to the run-time of these compressors, which depends directly on the volume of natural gas gathered. As part of our contracts with our DFW Midstream system customers, we physically retain a percentage of throughput volumes that we subsequently sell to offset the power costs we incur. With respect to the Mountaineer Midstream, Bison Midstream and Grand River systems, we either (i) consume physical gas on the system to operate our gas-fired compressors or (ii) charge our customers for the power costs we incur to operate our electric-drive compressors.

EBITDA, Adjusted EBITDA and Distributable Cash Flow

EBITDA, adjusted EBITDA and distributable cash flow are used as supplemental financial measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others.

EBITDA and adjusted EBITDA are used to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unitholders and general partner;
- 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; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

In addition, adjusted EBITDA is used to assess:

- the financial performance of our assets without regard to the impact of the timing of minimum volume commitments shortfall payments under our gas gathering agreements or the timing of impairments or other noncash income or expense items.

Distributable cash flow is used to assess:

- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions to our unitholders; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

For additional information, see the "Results of Operations" and "Non-GAAP Financial Measures" sections herein and Note 3 to the audited consolidated financial statements.

Results of Operations

Our financial results are recognized as follows:

Gathering services and other fees. Revenue earned from the natural gas gathering, treating and processing services that we provide to our natural gas and crude oil producer customers.

Natural gas, NGLs and condensate sales and other. Revenue earned from (i) the sale of physical natural gas and natural gas liquids purchased from our customers under percentage-of-proceeds and keep-whole arrangements with certain of our customers on the Bison Midstream and Red Rock gathering systems, (ii) the sale of natural gas we retain from our DFW Midstream customers and (iii) the sale of condensate we retain from our gathering services at Grand River.

Amortization of favorable and unfavorable contracts. The amortization of favorable and unfavorable contracts relates to gas gathering agreements that were deemed to be above or below market at the acquisition of the DFW Midstream system. We amortize these contracts on a units-of-production basis over the life of the applicable contract.

Cost of natural gas and NGLs. The cost of natural gas and NGLs represents the costs associated with the percent-of-proceeds and keep-whole arrangements under which we sell natural gas purchased from certain of our customers on the Bison Midstream and Red Rock gathering systems.

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. Operation and maintenance also includes our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system.

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.

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

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

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

Interest expense. Interest expense associated with our revolving credit facility and senior notes.

Affiliated interest expense. Interest cost related to the $200.0 million promissory notes that we issued to affiliates in connection with the acquisition of the Grand River system in 2011. The promissory notes were repaid in 2012.

Income tax expense. Since we are structured as a partnership, we are generally not subject to federal and state income taxes, except the Texas Margin Tax, which is reflected herein.

Items Affecting the Comparability of Our Financial Results

SMLP's historical results of operations may not be comparable to its future results of operations for the reasons described below:

- The audited consolidated financial statements reflect the results of operations of Red Rock Gathering since October 23, 2012. We accounted for the Red Rock Drop Down on an "as-if pooled" basis because the transaction was executed by entities under common control. Red Rock Gathering's contribution to the Partnership's financial and operating results have been reflected in the financial and operating results of its parent, Grand River.
- The audited consolidated financial statements reflect the results of operations of Bison Midstream since February 16, 2013. We accounted for the Bison Drop Down on an "as-if pooled" basis because the transaction was executed by entities under common control.
- The audited consolidated financial statements reflect the results of operations of Mountaineer Midstream since June 22, 2013.

For additional information, see the notes to the audited consolidated financial statements.

Table of Contents

The following table presents certain consolidated and other financial and operating data as of or for the years ended December 31.

	Year ended December 31,			Percentage Change	
	2014	2013	2012	2014 v. 2013	2013 v. 2012
	(Dollars in thousands)				
Revenues:					
Gathering services and other fees	$235,033	$205,346	$154,139	14 %	33 %
Natural gas, NGLs and condensate sales and other	96,597	88,606	20,476	9 %	*
Amortization of favorable and unfavorable contracts	(944)	(1,032)	(192)	*	*
Total revenues	330,686	292,920	174,423	13 %	68 %
Costs and expenses:					
Cost of natural gas and NGLs	58,094	44,233	3,224	31 %	*
Operation and maintenance	76,272	72,465	53,882	5 %	34 %
General and administrative	34,017	30,105	22,182	13 %	36 %
Transaction costs	730	2,841	2,025	(74)%	40 %
Depreciation and amortization	82,990	69,962	36,674	19 %	91 %
Loss on asset sales, net	442	113	—	*	*
Goodwill impairment	54,199	—	—	*	— %
Long-lived asset impairment	5,505	—	—	*	— %
Total costs and expenses	312,249	219,719	117,987	42 %	86 %
Other income	1,189	5	9	*	*
Interest expense	(40,159)	(19,173)	(7,340)	109 %	*
Affiliated interest expense	—	—	(5,426)	— %	*
(Loss) income before income taxes	(20,533)	54,033	43,679	(138)%	24 %
Income tax expense	(631)	(729)	(682)	(13)%	7 %
Net (loss) income	$(21,164)	$53,304	$42,997	(140)%	24 %
Other Financial Data:					
EBITDA (1)	$103,556	$144,195	$93,302	(28)%	55 %
Adjusted EBITDA (1)	193,778	164,839	105,946	18 %	56 %
Capital expenditures (2)	128,325	109,376	77,296	17 %	42 %
Acquisitions of gathering systems (3)	315,872	458,914	—	*	*
Distributable cash flow (1)(2)	139,611	128,141	90,947	9 %	41 %
Operating Data:					
Miles of pipeline as of December 31	2,348	2,283	1,874	3 %	22 %
Aggregate average throughput (MMcf/d)	1,418	1,138	952	25 %	20 %
Aggregate average throughput rate per Mcf	$0.46	$0.50	$0.41	(8)%	22 %

*Not considered meaningful

(1) See "Non-GAAP Financial Measures" herein for additional information on EBITDA, adjusted EBITDA and distributable cash flow as well as their reconciliations to the most directly comparable GAAP financial measure.

(2) See "Liquidity and Capital Resources" herein for additional information on capital expenditures.

(3) Reflects cash paid and value of units issued, if any, to fund acquisitions and/or drop downs. For additional information, see Note 15 to the audited consolidated financial statements.

53

Table of Contents

Consolidated Overview of the Years Ended December 31, 2014, 2013 and 2012

Volumes. For the year ended December 31, 2014, our aggregate throughput volumes increased to an average of 1,418 MMcf/d, compared with an average of 1,138 MMcf/d for the year ended December 31, 2013. The increase in volume throughput largely reflects the contribution from Mountaineer Midstream and the Grand River system as a result of growth at Red Rock Gathering, partially offset by volume throughput declines on the DFW Midstream and Legacy Grand River systems. Volume throughput on the DFW Midstream system benefited in the prior-year period due to the first quarter 2013 commissioning of an additional compressor which increased throughput capacity on the DFW Midstream system by 40 MMcf/d.

Our aggregate throughput volumes increased to an average of 1,138 MMcf/d for the year ended December 31, 2013, compared with an average of 952 MMcf/d for the year ended December 31, 2012. The 2013 increase in volume throughput largely reflects the combined effect of contributions from Bison Midstream and Mountaineer Midstream, an increase in volume throughput at Red Rock Gathering and the comparative impact of a temporary production curtailment by DFW Midstream's anchor customer during the first and second quarters of 2012.

Revenues. For the year ended December 31, 2014, total revenues increased $37.8 million, or 13%, and primarily reflect:

- overall growth at Red Rock Gathering;
- an increase in gathering services and other fees at Mountaineer Midstream, due in large part to the partial year of ownership in 2013;
- overall growth at Bison Midstream primarily due to higher volume throughput;
- an overall decline in revenues on the DFW Midstream primarily due to lower volume throughput.

For the year ended December 31, 2013, total revenues increased $118.5 million, or 68%, and primarily reflect:

- a full year of operations for Red Rock Gathering;
- Bison Midstream's contribution to natural gas, NGLs and condensate sales and other;
- Mountaineer Midstream's contribution to gathering services and other fees; and
- an increase in revenues for the DFW Midstream system due to higher volume throughput.

Costs and Expenses. For the year ended December 31, 2014, total costs and expenses increased $92.5 million, or 42%, primarily due to a goodwill impairment for Bison Midstream, an increase in depreciation and amortization across our gathering systems and an increase in cost of natural gas and NGLs for Bison Midstream and Red Rock Gathering.

For the year ended December 31, 2013, total costs and expenses increased $101.7 million, or 86%, primarily as a result of a full year of operations for Red Rock Gathering and the partial-year contributions from Bison Midstream and Mountaineer Midstream in 2013.

Segment Overview of the Years Ended December 31, 2014, 2013 and 2012

Marcellus Shale. The Mountaineer Midstream gathering system provides our midstream services for the Marcellus Shale reportable segment. We acquired Mountaineer Midstream in June 2013. Marcellus Shale volume throughput averaged 382 MMcf/d for the year ended December 31, 2014, and reflects the continuation of active drilling by Antero, our anchor customer, and the connection of new wells upstream of the Mountaineer Midstream system and as new, upstream compressor stations were commissioned by third parties, also contributing to volume throughput. The Zinnia Loop project, which increased throughput capacity on the Mountaineer Midstream system from 550 MMcf/d to 1,050 MMcf/d, was commissioned at the end of the third quarter of 2014. The Zinnia Loop is supported by a long-term minimum revenue commitment from Antero.

Table of Contents

Information regarding our operations in the Marcellus Shale as of or for the years ended December 31 follow.

	Marcellus Shale(1)			
	Year ended December 31,		Percentage Change	
	2014	2013	2014 v. 2013	
	(Dollars in thousands)			
Revenues:				
Gathering services and other fees	$22,694	$9,588	137	%
Total revenues	22,694	9,588	137	%
Costs and expenses:				
Operation and maintenance	4,560	2,447	86	%
General and administrative	2,194	808	*	
Depreciation and amortization	7,648	3,998	91	%
Total costs and expenses	14,402	7,253	99	%
Add:				
Depreciation and amortization	7,648	3,998		
Segment adjusted EBITDA	$15,940	$6,333	*	
Average throughput (MMcf/d)(2)	382	87	*	

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* Not considered meaningful
(1) Contract terms related to throughput rate per MCF are excluded for confidentiality purposes.
(2) For the period of SMLP's ownership in 2013, average throughput was 164 MMcf/d.

Gathering Services and Other Fees. Gathering services and other fees benefited in 2014 from a full year of operations under SMLP's management as well as our build out of the Mountaineer system to keep pace with increases in production from Antero as processing capacity at MarkWest’s Sherwood Processing Complex increased.

Total Costs and Expenses. Total costs and expenses, and the components thereof, increased during the year ended December 31, 2014, largely as a result of a full year of operations in 2014.

Williston Basin. The Bison Midstream gathering system provides our midstream services for the Williston Basin reportable segment. Bison Midstream was acquired from a subsidiary of Summit Investments in June 2013. Our results include activity for Bison Midstream since February 16, 2013, the date on which common control began. Williston Basin volume throughput averaged 18 MMcf/d for the year ended December 31, 2014, compared with 16 MMcf/d during our period of ownership in 2013. The increase in volume throughput in 2014 primarily reflects additional pad site connections and newly installed compression capacity, which improved system hydraulics. During the last half of 2014, Bison Midstream's results of operations were negatively impacted by declining commodity prices, most notably in relation to its percent-of-proceeds arrangements.

Table of Contents

Information regarding our operations in the Williston Basin as of or for the years ended December 31 follow.

	Williston Basin			
	Year ended December 31,		Percentage Change	
	2014	2013	2014 v. 2013	
	(Dollars in thousands, except fee-rate data)			
Revenues:				
Gathering services and other fees	$6,414	$3,605	78	%
Natural gas, NGLs and condensate sales and other	56,040	47,130	19	%
Total revenues	62,454	50,735	23	%
Costs and expenses:				
Cost of natural gas and NGLs	40,159	31,036	29	%
Operation and maintenance	9,113	4,200	117	%
General and administrative	3,503	2,234	57	%
Depreciation and amortization	18,132	16,057	13	%
Loss on asset sales	296	—	*	
Goodwill impairment	54,199	—	*	
Total costs and expenses	125,402	53,527	134	%
Add:				
Depreciation and amortization	18,132	16,057		
Adjustments related to MVC shortfall payments	10,743	3,600		
Loss on asset sales	296	—		
Goodwill impairment	54,199	—		
Segment adjusted EBITDA	$20,422	$16,865	21	%
Average throughput (MMcf/d)(1)	18	14	29	%
Average throughput rate per Mcf	$3.46	$3.86	(10	)%

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* Not considered meaningful

(1) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 16 MMcf/d.

Gathering Services and Other Fees. Gathering services and other fees increased during the year ended December 31, 2014 primarily a result of increased volumes under our percent-of-proceeds arrangements on the Bison Midstream system. The aggregate average throughput rate declined to $3.46 per Mcf in 2014 from $3.86 per Mcf in 2013, primarily as a result of a shift in volume mix.

Natural Gas, NGLs and Condensate Sales and Other. The increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2014 was primarily a result of increased volumes under percent-of-proceeds arrangements, partially offset by declining commodity prices.

Cost of Natural Gas and NGLs. The increase in the cost of natural gas and NGLs during the year ended December 31, 2014 was primarily a result of increased volumes under percent-of-proceeds arrangements, partially offset by declining commodity prices.

Operation and Maintenance. Operation and maintenance expense increased during the year ended December 31, 2014, largely as a result of a $1.6 million increase in salaries, benefits and incentive compensation, a $0.7 million increase in chemicals expense, a $0.4 million for field communications and meters and a $0.4 million increase in property taxes.

General and Administrative. General and administrative expense increased during the year ended December 31, 2014, largely as a result of an increase in salaries, benefits and incentive compensation primarily as a result of increased head count.

56

Table of Contents

Depreciation and Amortization. The increase in depreciation and amortization expense during the year ended December 31, 2014 was largely driven by an increase in contract amortization and assets placed into service.
Goodwill Impairment. During the fourth quarter of 2014, we determined that the goodwill associated with the Bison Midstream system had been impaired. Based on available information, we have preliminarily recognized an estimated goodwill impairment of $54.2 million. See "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets—Goodwill" and Note 5 to the audited consolidated financial statements for additional information.

Barnett Shale. The DFW Midstream gathering system provides our midstream services for the Barnett Shale reportable segment. On September 30, 2014, DFW Midstream acquired certain natural gas gathering assets (the "Lonestar assets"). The Lonestar assets gather natural gas under two long-term, fee-based gathering agreements.
DFW Midstream volume throughput declined to 358 MMcf/d during 2014 from 391 MMcf/d in 2013 primarily reflecting continued natural declines and lack of drilling activity by DFW Midstream's anchor customer, partially offset by the benefit from the Lonestar assets as well as several customers bringing new wells on line early in the second quarter of 2014. For the year ended December 31, 2014, volume throughput was impacted by multiple customers temporarily shutting-in several large pad sites to drill or complete new wells. These shut-ins began in the third quarter of 2013 and continued into late 2014 when customer production recommenced from several pad sites.
Volume throughput increased to 391 MMcf/d during 2013 from 354 MMcf/d in 2012 largely as a result of the comparative impact of a temporary production curtailment by DFW Midstream's anchor customer during the first and second quarters of 2012 and a short-term boost from the January 2013 commissioning of a compressor which increased system capacity by 40 MMcf/d.
Information regarding our operations in the Barnett Shale as of or for the years ended December 31 follow.

	Barnett Shale				
	Year ended December 31,			Percentage Change	
	2014	2013	2012	2014 v. 2013	2013 v. 2012
	(Dollars in thousands, except fee-rate data)				
Revenues:					
Gathering services and other fees	$80,453	$88,730	$80,844	(9)%	10 %
Natural gas, NGLs and condensate sales and other	13,492	17,626	12,801	(23)%	38 %
Amortization of favorable and unfavorable contracts	(944)	(1,032)	(192)	(9)%	*
Total revenues	93,001	105,324	93,453	(12)%	13 %
Costs and expenses:					
Operation and maintenance	29,438	31,784	25,160	(7)%	26 %
General and administrative	4,607	6,129	6,453	(25)%	(5)%
Depreciation and amortization	15,657	13,929	12,078	12 %	15 %
Loss on asset sales	—	113	—	*	*
Long-lived asset impairment	5,505	—	—	*	— %
Total costs and expenses	55,207	51,955	43,691	6 %	19 %
Add:					
Depreciation and amortization	16,601	14,961	12,270		
Adjustments related to MVC shortfall payments	628	1,030	1,638		
Loss on asset sales	—	113	—		
Long-lived asset impairment	5,505	—	—		
Segment adjusted EBITDA	$60,528	$69,473	$63,670	(13)%	9 %
Average throughput (MMcf/d)	358	391	354	(8)%	10 %
Average throughput rate per Mcf	$0.59	$0.59	$0.58	— %	2 %

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* Not considered meaningful

Table of Contents

Gathering Services and Other Fees. Gathering services and other fees decreased during the year ended December 31, 2014, reflecting the continued natural decline in volumes and lack of producer drilling activity. The aggregate average throughput rate was unchanged year over year.

The increase in gathering services and other fees during the year ended December 31, 2013 primarily reflected the comparative impact of the production curtailment in the first half of 2012, a short-term throughput volume boost which increased system capacity by 40 MMcf/d (both noted above) and an increase in the aggregate average throughput rate per Mcf.

Natural Gas, NGLs and Condensate Sales and Other. The decrease in natural gas, NGLs and condensate sales and other for the year ended December 31, 2014, was primarily a result of a decline in revenue associated with natural gas retainage sales at DFW Midstream.

The increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2013, was primarily a result of higher throughput volumes and the associated retainage on our DFW Midstream system, and an increase in the prices we were able to obtain for natural gas sales.

Operation and Maintenance. Operation and maintenance expense decreased during the year ended December 31, 2014, largely as a result of a $3.8 million decline in third-party natural gas treating expenses, partially offset by a $0.9 million increase in insurance expense and a $0.6 million increase in compression-related expenses.

Operation and maintenance expense increased during the year ended December 31, 2013, largely as a result of a $4.3 million increase in power-related costs and a $1.6 million increase in third-party natural gas treating expenses.

General and Administrative. General and administrative expense decreased during the year ended December 31, 2014, largely as a result of a decrease in the proportionate share of salaries, benefits and incentive compensation allocated to the segment and a decline in professional services fees.

Depreciation and Amortization. The increases in depreciation and amortization expense during the years ended December 31, 2014 and 2013 largely reflect the impact of assets placed in service.

Long-Lived Asset Impairment. The long-lived asset impairment recognized in 2014 represents the write off of certain property, plant and equipment balances associated with a DFW Midstream compressor station project that was terminated and replaced with a pipeline looping project. See "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets—Property, Plant and Equipment and Intangible Assets" and Note 4 to the audited consolidated financial statements for additional information.

Piceance Basin. The Legacy Grand River and Red Rock Gathering systems provide our midstream services for the Piceance Basin reportable segment. Red Rock Gathering became part of the Grand River system in connection with the Red Rock Drop Down in March 2014. As noted above, our results include activity for Red Rock Gathering since October 23, 2012, the date on which common control began. For additional information, see the notes to the audited consolidated financial statements. References to the Grand River system refer collectively to the Legacy Grand River system and Red Rock Gathering.

Volume throughput for the Piceance Basin increased to 660 MMcf/d during 2014 from 646 MMcf/d during 2013 primarily as a result of growth at Red Rock Gathering. Volume throughput from Red Rock Gathering was favorably impacted by new pad site connections for WPX Energy, Inc. and Ursa Resources Group II as well as the March 2014 start-up of a cryogenic processing plant servicing production from Black Hills Corporation. Volume throughput on the Legacy Grand River system declined in 2014 primarily as a result of Encana's temporary suspension of drilling activities, which began in the fourth quarter of 2013.

Volume throughput for the Piceance Basin increased to 646 MMcf/d during 2013 from 598 MMcf/d during 2012 primarily as a result of growth at Red Rock Gathering, partially offset by lower drilling activity, including Encana as noted above, and the natural decline of previously drilled Mancos/Niobrara wells on our Legacy Grand River system. Volume growth from Red Rock Gathering's anchor customers continues to offset volume declines from the Legacy Grand River system. This shift in volume throughput mix has translated into higher average gathering rates per Mcf. Further, certain of our gas gathering agreements for the Grand River system include MVCs that increase in both rate and volume commitment over the next few years and largely mitigate the financial impact associated with declining volumes from certain customers. As a result, lower volume throughput for the customers subject to these MVCs translated into larger MVC shortfall payments during 2014 and 2013.

Table of Contents

Information regarding our operations in the Piceance Basin as of or for the years ended December 31 follow.

	Piceance Basin				
	Year ended December 31,			Percentage Change	
	2014	2013	2012	2014 v. 2013	2013 v. 2012
	(Dollars in thousands, except fee-rate data)				
Revenues:					
Gathering services and other fees	$125,472	$103,423	$74,286	21 %	39 %
Natural gas, NGLs and condensate sales and other	27,065	23,850	7,675	13 %	*
Total revenues	152,537	127,273	81,961	20 %	55 %
Costs and expenses:					
Cost of natural gas and NGLs	17,935	13,197	3,224	36 %	*
Operation and maintenance	33,111	33,964	28,709	(3)%	18 %
General and administrative	8,732	11,566	5,979	(25)%	93 %
Depreciation and amortization	40,965	35,527	24,310	15 %	46 %
Loss on asset sales, net	146	—	—	*	— %
Total costs and expenses	100,889	94,254	62,222	7 %	51 %
Other income	1,185	—	—	*	— %
Add:					
Depreciation and amortization	40,965	35,527	24,310		
Adjustments related to MVC shortfall payments	15,194	12,395	9,130		
Loss on asset sales, net	146	—	—		
Less:					
Impact of purchase price adjustments	1,185	—	—		
Segment adjusted EBITDA	$107,953	$80,941	$53,179	33 %	52 %
Average throughput (MMcf/d)(1)	660	646	598	2 %	8 %
Average throughput rate per Mcf	$0.49	$0.40	$0.31	23 %	29 %

* Not considered meaningful

(1) For the year ended December 31, 2012. For the period of SMLP's ownership in 2012, average throughput was 715 MMcf/d.

Gathering Services and Other Fees. Gathering services and other fees increased during the year ended December 31, 2014, largely due to the proportionate contribution of higher margin volume throughput from certain customers and the first quarter 2014 commissioning of a natural gas processing plant. The aggregate average throughput rate increased to $0.49 per Mcf during 2014 from $0.40 per Mcf during 2013 largely as a result of the shift in volume throughput mix noted above.

Gathering services and other fees increased during the year ended December 31, 2013, largely as a result of the the full-year contribution from Red Rock Gathering in 2013. The aggregate average throughput rate increased to $0.40 per Mcf during 2013 from $0.31 per Mcf during 2012, largely as a result of the shift in volume throughput mix noted above. For the year ended December 31, 2013, gathering services and other fees included a $30.8 million contribution as a result of the Red Rock Drop Down, compared with a $4.8 million contribution in 2012.

Natural Gas, NGLs and Condensate Sales and Other. The increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2014, was primarily a result of growth at Red Rock Gathering.

The increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2013, was primarily a result of the Red Rock Drop Down and an increase in the prices we were able to obtain for natural gas sales. For the year ended December 31, 2013, natural gas, NGLs and condensate sales and other included a $19.3

million contribution as a result of the Red Rock Drop Down, compared with a $4.2 million contribution in 2012.
Cost of Natural Gas and NGLs. The increase in the year ended December 31, 2014 was primarily a result of the growth at Red Rock Gathering system.

Table of Contents

For the year ended December 31, 2013, cost of natural gas and NGLs included a $13.2 million contribution as a result of the Red Rock Drop Down, compared with a $3.2 million contribution in 2012.
Operation and Maintenance. Operation and maintenance expense decreased during the year ended December 31, 2014, largely as a result of a $0.8 million decrease in property tax expense.
Operation and maintenance expense increased during the year ended December 31, 2013, largely as a result of the Red Rock Drop Down. For the year ended December 31, 2013, operation and maintenance expense included a $12.5 million contribution as a result of the Red Rock Drop Down in 2013, compared with a $2.2 million contribution in 2012. The increase in operation and maintenance expense was partially offset by a $2.8 million decline in compressor lease and contract maintenance expenses primarily as a result of our purchase of previously leased compression assets in the first quarter of 2013.
General and Administrative. General and administrative expense decreased during the year ended December 31, 2014, largely as a result of a decrease in the proportionate share of salaries, benefits and incentive compensation allocated to the segment.
General and administrative expense increased during the year ended December 31, 2013, largely as a result of an increase in salaries, benefits and incentive compensation primarily due to the Red Rock Drop Down. For the year ended December 31, 2013, general and administrative expense included a $5.5 million contribution as a result of the Red Rock Drop Down, compared with a $0.8 million contribution in 2012.
Depreciation and Amortization. The increase in depreciation and amortization expense during the year ended December 31, 2014 was largely driven by an increase in contract amortization and assets placed into service on the Grand River system.
Depreciation and amortization expense increased during the year ended December 31, 2013 largely due to the Red Rock Drop Down. An increase in contract amortization and assets placed into service in connection with the development of Grand River Gathering also contributed to the increase. Depreciation and amortization expense also included a $9.1 million contribution as a result of the Red Rock Drop Down in 2013, compared with a $1.4 million contribution in 2012.
Other income. Other income represents the write off of certain balances that had been previously recognized in connection with the purchase accounting for the Legacy Grand River system. See "Non-GAAP Financial Measures—Non-GAAP reconciliations items to note" and Note 15 to the audited consolidated financial statements for additional information.

Corporate. Corporate represents those revenues and expenses 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, transaction costs and interest expense. Items to note follow.
General and Administrative. General and administrative expense increased during the year ended December 31, 2014, largely as a result of an increase in salaries, benefits and incentive compensation primarily due to increased head count, an increase in professional expenses associated with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 and our adoption of Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO 2013"). The substantial majority of our first-year COSO 2013 implementation expenses are not expected to be incurred beyond 2014.
Transaction Costs. Transaction costs for the year ended December 31, 2014, primarily related to financial and legal advisory costs associated with the Red Rock Drop Down. Transaction costs were $2.8 million for the year ended December 31, 2013, of which $2.0 million related to the acquisition of the Mountaineer Midstream system and $0.8 million related to the acquisition of the Bison Midstream system. Transaction costs of $2.0 million in 2012 largely reflect costs associated with Summit Investments' acquisition of the Red Rock Gathering in October 2012.
Interest Expense and Affiliated Interest Expense. The increase in interest expense during the year ended December 31, 2014, was primarily driven by our issuance of $300.0 million of 5.50% senior notes in July 2014, our issuance of $300.0 million of 7.50% senior notes in June 2013, and a higher average outstanding balance on our revolving credit facility as a result of our June 2013 and March 2014 borrowings to partially fund the Partnership's acquisition capital expenditures. We used the proceeds from our July 2014 5.50% senior notes offering to partially pay down our

revolving credit facility.

The increase in interest expense during the year ended December 31, 2013, primarily reflects our issuance of $300.0 million of 7.50% senior notes in June 2013. Additionally, higher balances on our revolving credit facility

Table of Contents

beginning in May 2012 as well as an increase in commitment fees as a result of the May 2012 amendment and restatement of the revolving credit facility, which increased our borrowing capacity by $265.0 million and the June 2013 amendment and restatement, which increased our borrowing capacity by $50.0 million, also contributed to the increase in interest expense.

Affiliated interest expense for the year ended December 31, 2012 related to the $200.0 million promissory notes that we issued to the Sponsors in connection with the acquisition of the Grand River system in October 2011. The promissory notes were partially prepaid in May 2012 with the remaining balance repaid in July 2012.

Non-GAAP Financial Measures

EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We define EBITDA as net income or loss, plus interest expense, income tax expense, and depreciation and amortization, less interest income and income tax benefit. We define adjusted EBITDA as EBITDA plus adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less other noncash income or gains. We define distributable cash flow as adjusted EBITDA plus cash interest received, less cash interest paid, senior notes interest, cash taxes paid and maintenance capital expenditures. We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition and results of operations.

Net income or loss and net cash provided by operating activities are the GAAP financial measures most directly comparable to EBITDA, adjusted EBITDA and distributable cash flow. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Furthermore, each of these non-GAAP financial measures has limitations as an analytical tool because it excludes some but not all items that affect the most directly comparable GAAP financial measure. Some of these limitations include:

- certain items excluded from EBITDA, adjusted EBITDA and distributable cash flow are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure;
- EBITDA, adjusted EBITDA, and distributable cash flow do not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- EBITDA, adjusted EBITDA, and distributable cash flow do not reflect changes in, or cash requirements for, our working capital needs;
- although depreciation and amortization are noncash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA, adjusted EBITDA and distributable cash flow do not reflect any cash requirements for such replacements; and
- our computations of EBITDA, adjusted EBITDA and distributable cash flow may not be comparable to other similarly titled measures of other companies.

We compensate for the limitations of EBITDA, adjusted EBITDA and distributable cash flows as analytical tools by reviewing the comparable GAAP financial measures, understanding the differences between the financial measures and incorporating these data points into our decision-making process.

EBITDA, adjusted EBITDA or distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because EBITDA, adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Non-GAAP reconciliations items to note. The following items should be noted when reviewing our non-GAAP reconciliations:

- EBITDA, adjusted EBITDA, distributable cash flow and net cash provided by operating activities include transaction costs. These unusual expenses are settled in cash. For additional information, see "Results of Operations—Corporate" herein.
- Adjustments related to MVC shortfall payments account for (i) the net increases or decreases in deferred revenue for MVC shortfall payments and (ii) our inclusion of expected annual MVC shortfall payments. We include a proportional amount of these historical or expected minimum volume commitment shortfall payments in each quarter prior to the quarter in which we actually receive the shortfall payment.

61

Table of Contents

- The goodwill impairment recognized in the year ended December 31, 2014 relates to the Bison Midstream system of our Williston Basin segment. See "Results of Operations—Williston Basin," "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" and Note 5 to the audited consolidated financial statements for additional information.
- The long-lived asset impairment recognized in the year ended December 31, 2014 relates to the DFW Midstream system of our Barnett Shale segment. See "Results of Operations—Barnett Shale," "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" and Note 4 to the audited consolidated financial statements for additional information.
- The impact of purchase price adjustments reflects certain balances previously recognized in connection with the Predecessor's purchase accounting for the Legacy Grand River system that we wrote off during the fourth quarter of 2014. This write off was recognized in other income. See "Results of Operations—Piceance Basin" and Note 15 to the audited consolidated financial statements for additional information.
- Senior notes interest represents the net of interest expense accrued and paid during the period. See "Liquidity and Capital Resources—Long-Term Debt" and Note 7 to the audited consolidated financial statements for additional information.
- Maintenance capital expenditures 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. In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. For the year ended December 31, 2012 the calculation of distributable cash flow and adjusted distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures.
- Interest expense presented in the net income-basis non-GAAP reconciliation includes amortization of deferred loan costs while interest expense presented in the cash flow-basis non-GAAP reconciliation is adjusted to exclude amortization of deferred loan costs. See the consolidated statements of cash flows for additional information.

Table of Contents

Net Income-Basis Non-GAAP Reconciliation. The following table presents a reconciliation of net income to EBITDA, adjusted EBITDA and distributable cash flow for the periods indicated.

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Reconciliation of Net Income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net (loss) income	$(21,164)	$53,304	$42,997
Add:			
Interest expense	40,159	19,173	12,766
Income tax expense	631	729	682
Depreciation and amortization	82,990	69,962	36,674
Amortization of favorable and unfavorable contracts	944	1,032	192
Less:			
Interest income	4	5	9
EBITDA	$103,556	$144,195	$93,302
Add:			
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	4,696	3,506	1,876
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Less:			
Impact of purchase price adjustments	1,185	—	—
Adjusted EBITDA	$193,778	$164,839	$105,946
Add:			
Cash interest received	4	5	9
Less:			
Cash interest paid	31,524	9,016	8,283
Senior notes interest	6,733	12,125	—
Cash taxes paid	—	660	650
Maintenance capital expenditures	15,914	14,902	6,075
Distributable cash flow	$139,611	$128,141	$90,947

Table of Contents

Cash Flow-Basis Non-GAAP Reconciliation. The following table presents a reconciliation of net cash provided by operating activities to EBITDA, adjusted EBITDA and distributable cash flow for the periods indicated.

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Reconciliation of Net Cash Provided by Operating Activities to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net cash provided by operating activities	$147,935	$140,689	$89,392
Add:			
Interest expense	37,389	16,927	5,882
Income tax expense	631	729	682
Impact of purchase price adjustments	1,185	—	—
Changes in operating assets and liabilities	(18,738)	(10,526)	(769)
Less:			
Unit-based compensation	4,696	3,506	1,876
Interest income	4	5	9
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
EBITDA	$103,556	$144,195	$93,302
Add:			
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	4,696	3,506	1,876
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Less:			
Impact of purchase price adjustments	1,185	—	—
Adjusted EBITDA	$193,778	$164,839	$105,946
Add:			
Cash interest received	4	5	9
Less:			
Cash interest paid	31,524	9,016	8,283
Senior notes interest	6,733	12,125	—
Cash taxes paid	—	660	650
Maintenance capital expenditures	15,914	14,902	6,075
Distributable cash flow	$139,611	$128,141	$90,947

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 flow generated from our operations, borrowings under our revolving credit facility and future issuances of equity and debt securities. Prior to our IPO in October 2012, we largely relied on internally generated cash flows and capital contributions from the Sponsors to satisfy our capital expenditure requirements.

Table of Contents

Capital Markets Activity

November 2013 Shelf Registration Statement. In October 2013, we filed a shelf registration statement with the SEC to register up to $1.2 billion of equity and debt securities in primary offerings as well as all of the 14,691,397 common units held by a subsidiary of Summit Investments in accordance with our obligations under several registration rights agreements. In November 2013, the SEC declared our shelf registration statement effective.

In March 2014, we completed an underwritten public offering of 10,350,000 common units at a price of $38.75 per unit, of which 5,300,000 common units were offered by the Partnership and 5,050,000 common units were offered by a subsidiary of Summit Investments. Concurrent with the offering, our general partner made a capital contribution to maintain its 2% general partner interest. We used the proceeds from our primary offering of common units and the general partner capital contribution to fund a portion of the purchase of Red Rock Gathering.

In September 2014, a subsidiary of Summit Investments completed an underwritten public offering of 4,347,826 SMLP common units. We did not receive any proceeds from the this offering.

Following these offerings, we can issue up to $1.0 billion of debt and equity securities in primary offerings and 5,293,571 common units pursuant to this shelf registration statement.

July 2014 Shelf Registration Statement. In July 2014, we filed a registration statement with the SEC to issue an unlimited amount of debt and equity securities and shortly thereafter completed a public offering of $300.0 million aggregate principal 5.5% senior notes due 2022. We used the proceeds to repay a portion of the outstanding borrowings under our revolving credit facility.

Private Offerings of Debt and Equity. In June 2013, we issued $300.0 million unregistered 7.5% senior unsecured notes and guarantees notes maturing July 1, 2021 (the "7.5% senior notes") and used the net proceeds to partially fund the acquisition of Mountaineer Midstream. In March 2014, the SEC declared our registration statement to exchange all of the unregistered 7.5% senior notes and guarantees for registered senior notes and guarantees with substantially identical terms effective. In April 2014, the exchange period concluded with 100% of the unregistered senior notes being exchanged for registered notes.

In June 2013, we issued common limited partner units and general partner interests to a subsidiary of Summit Investments to partially fund the Bison Drop Down and the acquisition of Mountaineer Midstream.

For additional information, see Notes 1, 7, 8 and 15 to the audited consolidated financial statements.

Long-Term Debt

Revolving Credit Facility. We have a $700.0 million senior secured revolving credit facility. The revolving credit facility is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of Summit Holdings' and its subsidiaries' assets are pledged as collateral under the revolving credit facility. The facility, and Summit Holdings' obligations, are guaranteed by SMLP and each of its subsidiaries. As of December 31, 2014, the outstanding balance of the revolving credit facility was $208.0 million and the unused portion totaled $492.0 million. As of December 31, 2014, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during 2014.

Senior Notes. In July 2014, Summit Holdings and its 100% owned finance subsidiary, Summit Midstream Finance Corp. ("Finance Corp.," together with Summit Holdings, the "Co-Issuers") co-issued $300.0 million of 5.50% senior unsecured notes maturing August 15, 2022. In June 2013, the Co-Issuers co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021. The 7.5% senior notes were initially sold in reliance on Rule 144A and Regulation S under the Securities Act. Effective as of April 7, 2014, all of the holders of our 7.5% senior notes exchanged their unregistered 7.5% senior notes and the guarantees of those notes for identical registered notes and guarantees. There were no defaults or events of default during 2014 on either series of senior notes.

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

Table of Contents

Cash Flows

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

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Net cash provided by operating activities	$147,935	$140,689	$89,392
Net cash used in investing activities	(443,872)	(518,791)	(77,296)
Net cash provided by (used in) financing activities	302,008	387,125	(16,224)
Change in cash and cash equivalents	$6,071	$9,023	$(4,128)

Operating activities. Cash flows from operating activities increased by $7.2 million for the year ended December 31, 2014 largely due to cash received as a result of MVCs.

Cash flows from operating activities increased by $51.3 million for the year ended December 31, 2013 largely as result of the Red Rock Drop Down, an increase in volumes on the DFW Midstream system and the contribution from the Bison Midstream and Mountaineer Midstream systems, partially offset by a decline in volumes on the Legacy Grand River system.

Investing activities. Cash flows used in investing activities for the year ended December 31, 2014 primarily reflect the Partnership's acquisition of Red Rock Gathering from a subsidiary of Summit Investments. Additional expenditures for the year ended December 31, 2014 primarily reflect construction of a processing plant on the Grand River Gathering system, projects to expand compression capacity on the Bison Midstream system, adding pipeline on the Mountaineer Midstream system, the February 2014 commissioning of a new natural gas treating facility on the DFW Midstream system and the purchase of the Lonestar assets.

Cash flows used in investing activities for the year ended December 31, 2013 were largely due to the acquisitions of Bison Midstream and Mountaineer Midstream. Additional expenditures in 2013 reflect the construction of seven miles of new gathering pipeline across the DFW Midstream system and the acquisition of previously leased compression assets on the Grand River system. We also commissioned a new compressor unit on the DFW Midstream system in January 2013. Development activities also included construction projects to connect new receipt points on the Bison Midstream and DFW Midstream systems and to expand compression capacity on the Bison Midstream system. We also began construction on a new 150 gallon per minute natural gas treating facility on the DFW Midstream system, which was commissioned in the first quarter of 2014.

In 2012, total capital expenditures were largely the result of the construction of new pipeline and compression infrastructure to connect new pad sites on our DFW Midstream system and to install meters and build out medium-pressure infrastructure on our Grand River system.

Table of Contents

Financing activities. Details of cash flows provided by financing activities for the three-year period ended December 31, 2014, were as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	$(122,224)	$(90,196)	$—
Borrowings under revolving credit facility	237,295	380,950	213,000
Repayments under revolving credit facility	(315,295)	(294,180)	(160,770)
Deferred loan costs	(5,320)	(10,608)	(3,344)
Tax withholdings on vested SMLP LTIP awards	(656)	—	—
Proceeds from issuance of common units	197,806	—	263,125
Contribution from general partner	4,235	2,229	—
Cash advance from Summit Investments to contributed subsidiaries, net	1,982	738	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	4,413	10,149	2,536
Issuance of senior notes	300,000	300,000	—
Issuance of units to affiliate in connection with the Mountaineer Acquisition	—	100,000	—
Repurchase of equity-based compensation awards	(228)	(11,957)	—
Red Rock Gathering cash contributed by Summit Investments	—	—	1,097
Repayment of promissory notes payable to Sponsors	—	—	(209,230)
Distributions to Sponsors	—	—	(123,138)
Net cash provided by (used in) financing activities	$302,008	$387,125	$(16,224)

Net cash provided by financing activities for the year ended December 31, 2014 was primarily composed of the following:

- Proceeds from the July 2014 issuance of 5.5% senior notes, the net of which was used to pay down our revolving credit facility. We incurred loan costs of $5.1 million in connection with their issuance which will be amortized over the life of the 5.5% senior notes;
- Borrowings of $100.0 million under our revolving credit facility to partially fund the Red Rock Drop Down;
- Net proceeds from an offering of common units in March 2014, which were used to partially fund the Red Rock Drop Down; and
- Distributions declared in respect of the first, second and third quarters of 2014 and the fourth quarter of 2013 (paid in the first quarter of 2014).

Net cash provided by financing activities for the year ended December 31, 2013 was primarily composed of the following:

- Distributions declared in respect of the first, second and third quarters of 2013 and the fourth quarter of 2012 (paid in the first quarter of 2013);
- Borrowings under our revolving credit facility, of which $200.0 million was used to partially fund the Bison Drop Down and $110.0 million was used to partially fund the Mountaineer Acquisition;
- Proceeds from the June 2013 issuance of 7.5% senior notes, the net of which was used to pay down our revolving credit facility. We incurred loan costs of $7.4 million in connection with the senior notes issuance which will be amortized over the life of the 7.5% senior notes;
- Payments of $294.2 million on our revolving credit facility, all of which was funded by the June 2013 issuance of 7.5% senior notes;
- Issuance of $98.0 million of common units and $2.0 million of general partner interests to Summit Investments for cash to partially fund the Mountaineer Acquisition; and
- Our repurchase of the remaining vested DFW Net Profits Interests.

Table of Contents

Net cash used in financing activities for the year ended December 31, 2012 was primarily composed of the following:

- Borrowings of $163.0 million under the revolving credit facility in May 2012, of which we used $160.0 million to prepay principal amounts outstanding under certain unsecured promissory notes payable to the Sponsors and borrowings of $50.0 million in July 2012, of which we used $49.2 million to repay the balance of the unsecured promissory notes payable to the Sponsors; and
- Proceeds of $263.1 million from the issuance of our common units in connection with our IPO (including the proceeds from the exercise of the underwriters' option to purchase additional common units). We used $140.0 million of the IPO proceeds to pay down our revolving credit facility. We also paid $88.0 million to reimburse Summit Investments for certain capital expenditures it incurred with respect to assets it contributed to us and distributed $35.1 million to Summit Investments for the common units it sold from the units originally allocated to it in connection with the exercise of the underwriters' option to purchase additional common units.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2014:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt and interest payments (1)	$1,128,219	$47,014	$94,027	$292,678	$694,500
Purchase obligations (2)	19,434	15,859	3,462	113	—
Total contractual obligations	$1,147,653	$62,873	$97,489	$292,791	$694,500

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(1) For the purpose of calculating future interest on the revolving credit facility, assumes no change in balance or rate from December 31, 2014. Includes a 0.50% commitment fee on the unused portion of the revolving credit facility. See Note 7 to the audited consolidated financial statements for additional information.

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

Operating leases. A substantial majority of the operating leases that support our operations have been entered into by Summit Investments with the associated rent expense allocated to us. Future minimum lease payments associated with operating leases in the Partnership's name are immaterial. See Note 14 to the audited consolidated financial statements for additional information.

Capital Requirements

Our business is capital-intensive, requiring significant investment for the maintenance of existing gathering systems and the acquisition or 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.

In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. For the year ended December 31, 2012, distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures for nine months ended September 30, 2012.

For the year ended December 31, 2014, SMLP recorded total capital expenditures of $128.3 million, which included $15.9 million of maintenance capital expenditures. Total acquisition capital expenditures of $318.8 million included $307.9 million to fund the Red Rock Drop Down (including a $2.9 million working capital adjustment settled in 2015) and $10.9 million for the acquisition of the Lonestar assets. Other expansion capital expenditures during 2014 were primarily related to compression capacity expansion work on the Bison Midstream system and the construction of pipeline and additional compressor capacity for Mountaineer Midstream.

68

Table of Contents

We anticipate that we will continue to make significant expansion capital expenditures in the future. 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 expect that our future expansion capital expenditures will be funded by borrowings under the revolving credit facility and the issuance of debt and equity securities.

We believe that our existing $700.0 million revolving credit facility, which had approximately $492.0 million of available capacity at December 31, 2014, together with our access to the debt and equity capital markets, will be adequate to finance our acquisition strategy for the foreseeable future without adversely impacting our liquidity or our ability to make quarterly cash distributions to our unitholders.

Distributions

Based on the terms of our partnership agreement, we expect to distribute to unitholders most of the cash generated by our operations. For additional information, see "Our Cash Distribution Policy and Restrictions on Distributions" in Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities and Note 8 to the audited consolidated financial statements.

Credit Risk and Customer Concentration

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. For additional information, see Note 11 to the audited consolidated financial statements.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of or during the year ended December 31, 2014.

Critical Accounting Estimates

We prepare our financial statements in accordance with GAAP. These principles are established by the Financial Accounting Standards Board. 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 audited 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, our contract intangible assets and goodwill.

Property, Plant and Equipment and Intangible Assets. As of December 31, 2014, we had net property, plant and equipment with a carrying value of approximately $1.24 billion and net intangible assets with a carrying value of approximately $466.9 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. With respect to property, plant and equipment and our contract 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 approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash flows.

- During the fourth quarter of 2014, prices for natural gas, NGLs and crude oil continued to decline such that we identified a need to evaluate the goodwill associated with the Bison Midstream system. In connection with this evaluation, we also evaluated the property, plant and equipment and intangible assets of our Bison Midstream reporting unit for impairment and concluded that no impairment was necessary. During the fourth quarter of 2014, we also reviewed certain property, plant and equipment balances associated with a

Table of Contents

compressor station project on our DFW Midstream system that was terminated and concluded that a portion of their carrying value was no longer recoverable. As such, we wrote off approximately $5.5 million of costs and reflected the net impact of this action in long-lived asset impairment on the statement of operations.

- During the years ended December 31, 2013 and 2012, we concluded that none of our long-lived assets had been impaired.

For additional information, see Notes 2, 4 and 5 to the audited consolidated financial statements.

Goodwill. We evaluate goodwill for impairment annually on September 30. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value, including goodwill. We have three reporting units which have goodwill: (i) Grand River Gathering, (ii) Bison Midstream and (iii) Mountaineer Midstream.

We performed our annual goodwill impairment analysis as of September 30, 2014. We determined that the fair value of the Grand River Gathering and Mountaineer Midstream reporting units substantially exceeded their carrying value, including goodwill. We also determined that the fair value of the Bison Midstream reporting unit exceeded its carrying value, including $54.2 million of goodwill, although it did not exceed its carrying value by a substantial amount. In connection therewith, we concluded that the fair values of our reporting units exceeded their carrying values, including goodwill, and as such concluded that none of our goodwill had been impaired.

During the latter part of the fourth quarter of 2014, the declines in prices for natural gas, NGLs and crude oil accelerated, negatively impacting producers in each of our areas of operation. As a result, we considered whether the goodwill associated with our Grand River Gathering, Mountaineer Midstream and Bison Midstream reporting units could have been impaired. Our assessments related to Grand River Gathering and Mountaineer Midstream did not result in an indication that the associated goodwill had been impaired. Furthermore, we do not believe that either reporting unit is at risk of failing step one of the goodwill impairment test as of December 31, 2014 due to the substantial amounts by which each reporting unit's fair value, including goodwill, exceeded its carrying value, including goodwill.

We also assessed whether the goodwill associated with the Bison Midstream reporting unit could have been impaired. In connection therewith, we noted that a key Bison Midstream customer announced that it was delaying its previously announced drilling plans. The combined impact of (i) the price declines on revenues under its percent-of proceeds contracts and (ii) the Partnership's reduction in its forecasted volume assumption in response to the decline in our customer's drilling plans increased the likelihood that the goodwill associated with the Bison Midstream reporting unit was impaired. As such, we concluded that a triggering event occurred during the fourth quarter of 2014 requiring that we test the goodwill associated with the Bison Midstream reporting unit for impairment.

The results of our step one goodwill impairment testing indicated that the fair value of the Bison Midstream reporting unit was below its carrying value, including goodwill. This result required that we perform step two of the goodwill impairment test. To perform step two, we first determined the fair values of the identifiable assets and liabilities. Significant assumptions utilized in the determination of the fair value of each reporting unit's individual assets and liabilities included the determination of discount rate and contributing asset charge utilized in our contract intangibles, expected levels of throughput volume and associated capital expenditures and commodity prices.

Our preliminary estimates of the fair values of the identified assets and liabilities calculated in the step two testing of the Bison Midstream reporting unit indicated that all of the associated goodwill had been impaired. As such, we recorded an estimated goodwill impairment of $54.2 million. This amount represents our best estimate of impairment pending the finalization of the fair value calculations, which we expect to finalize in the first quarter of 2015.

See Notes 2 and 5 to the audited consolidated financial statements for additional information.

Minimum Volume Commitments

The majority of our gas gathering agreements provide for a monthly or annual MVC from our customers. As of December 31, 2014, we had MVCs totaling 3.8 Tcf through 2026. Under these monthly, quarterly or annual MVCs, our customers agree to ship a minimum volume of natural gas 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 contract month, quarter or year, as applicable, if its actual throughput volumes are less than its MVC for the applicable period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent periods to the extent that such customer's throughput volumes in subsequent periods exceed its MVC for that period.

Table of Contents

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 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 natural gas gathering agreement.
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, 2014, current deferred revenue totaled $2.4 million. Noncurrent deferred revenue totaled $55.2 million at December 31, 2014 and represents amounts that provide these customers the ability to offset their gathering fees over a period up to seven years to the extent that their throughput volumes exceed their MVC.
We billed $50.9 million of MVC shortfall payments to customers that did not meet their MVCs during 2014. Certain of our natural gas gathering agreements do not have credit banking mechanisms and as such, the MVC shortfall payments from these customers are accounted for as revenue in the period that they are earned. We recognized $1.5 million of gathering revenue due to the credit bank expiration of previous MVC shortfall payments and $22.7 million of gathering revenue associated with MVC shortfall payments in 2014. Of the billings for MVC shortfall payments, $26.4 million was recorded as deferred revenue on SMLP’s balance sheet because these customers have the ability to use these MVC shortfall payments to offset gathering fees related to future throughput in excess of future period MVCs. MVC shortfall payment adjustments in the fourth quarter of 2014 totaled $0.2 million and included adjustments related to future anticipated shortfall payments. The net impact on adjusted EBITDA of MVC billings and their recognition was $50.8 million.
The following table presents the impact of our MVC activity by reportable segment during the year ended December 31, 2014.

	Year ended December 31, 2014			
	MVC billings	Gathering revenue	Adjustments to MVC shortfall payments	Net impact to adjusted EBITDA
	(In thousands)			
Net change in deferred revenue:				
Williston Basin	$10,743	$—	$10,743	$10,743
Barnett Shale	2,609	1,525	821	2,346
Piceance Basin	14,813	—	14,813	14,813
Total change in deferred revenue	$28,165	$1,525	$26,377	$27,902
MVC shortfall payment adjustments:				
Marcellus Shale	$1,742	$1,742	$—	$1,742
Barnett Shale	495	495	(193)	302
Piceance Basin	20,462	20,462	381	20,843
Total MVC shortfall payment adjustments	$22,699	$22,699	$188	$22,887
Total	$50,864	$24,224	$26,565	$50,789

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

71

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness associated with the revolving credit facility. The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is probable that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical 1.0% increase (decrease) in interest rates would have increased (decreased) our interest expense by approximately $2.7 million for the year ended December 31, 2014.

Commodity Price Risk

We currently generate a substantial majority of our revenues pursuant to primarily long-term and fee-based gas gathering agreements, many of which include MVCs and areas of mutual interest. Our direct commodity price exposure relates to (i) our sale of physical natural gas we retain from our DFW Midstream customers, (ii) our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system, (iii) the sale of condensate volumes that we retain on the Grand River system and (iv) the sale of processed natural gas and natural gas liquids pursuant to our percent-of-proceeds and keep-whole contracts with certain of our customers on the Bison Midstream and Grand River Gathering systems. Our gas gathering agreements with our DFW Midstream customers permit us to retain a certain quantity of natural gas that we sell to offset the power costs we incur to operate our electric-drive compression assets. Our gas 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.

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

We have audited the accompanying consolidated balance sheets of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, partners' capital and membership interests, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Summit Midstream Partners, LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the disclosures in the accompanying financial statements have been retrospectively adjusted for a change in the presentation of reportable segments.

The consolidated financial statements give retrospective effect to the Partnership's acquisition of Bison Midstream, LLC and Red Rock Gathering, LLC from Summit Midstream Partners Holdings, LLC, as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Notes 1 and 15 to the consolidated financial statements.

The Partnership acquired the Mountaineer Midstream gathering system on June 21, 2013 as described in Note 15 to the consolidated financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2014, 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 March 2, 2015 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP
Dallas, Texas
March 2, 2015

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	2013
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$26,428	$20,357
Accounts receivable	83,612	67,877
Other current assets	3,289	4,741
Total current assets	113,329	92,975
Property, plant and equipment, net	1,235,652	1,158,081
Intangible assets, net	466,866	502,177
Goodwill	61,689	115,888
Other noncurrent assets	17,338	14,618
Total assets	$1,894,874	$1,883,739
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$12,852	$25,117
Due to affiliate	2,711	653
Deferred revenue	2,377	1,555
Ad valorem taxes payable	8,717	8,375
Accrued interest	18,858	12,144
Other current liabilities	11,939	11,729
Total current liabilities	57,454	59,573
Long-term debt	808,000	586,000
Noncurrent liability, net (Note 5)	5,577	6,374
Deferred revenue	55,239	29,683
Other noncurrent liabilities	1,715	372
Total liabilities	927,985	682,002
Commitments and contingencies (Note 14)		
Common limited partner capital (34,427 units issued and outstanding at December 31, 2014 and 29,080 units issued and outstanding at December 31, 2013)	649,060	566,532
Subordinated limited partner capital (24,410 units issued and outstanding at December 31, 2014 and 2013)	293,153	379,287
General partner interests (1,201 units issued and outstanding at December 31, 2014 and 1,091 units issued and outstanding at December 31, 2013)	24,676	23,324
Summit Investments' equity in contributed subsidiaries	—	232,594
Total partners' capital	966,889	1,201,737
Total liabilities and partners' capital	$1,894,874	$1,883,739

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,		
	2014	2013	2012
	(In thousands, except per-unit amounts)		
Revenues:			
Gathering services and other fees	$235,033	$205,346	$154,139
Natural gas, NGLs and condensate sales and other	96,597	88,606	20,476
Amortization of favorable and unfavorable contracts	(944)	(1,032)	(192)
Total revenues	330,686	292,920	174,423
Costs and expenses:			
Cost of natural gas and NGLs	58,094	44,233	3,224
Operation and maintenance	76,272	72,465	53,882
General and administrative	34,017	30,105	22,182
Transaction costs	730	2,841	2,025
Depreciation and amortization	82,990	69,962	36,674
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Total costs and expenses	312,249	219,719	117,987
Other income	1,189	5	9
Interest expense	(40,159)	(19,173)	(7,340)
Affiliated interest expense	—	—	(5,426)
(Loss) Income before income taxes	(20,533)	54,033	43,679
Income tax expense	(631)	(729)	(682)
Net (loss) income	$(21,164)	$53,304	$42,997
Less: net income attributable to the pre-IPO period (Note 1)	—	—	24,112
Less: net income attributable to Summit Investments (Note 1)	2,828	9,720	1,271
Net (loss) income attributable to SMLP	(23,992)	43,584	17,614
Less: net (loss) income attributable to general partner, including IDRs	3,125	1,035	352
Net (loss) income attributable to limited partners	$(27,117)	$42,549	$17,262
(Loss) earnings per limited partner unit (Note 9):			
Common unit – basic	$(0.49)	$0.86	$0.35
Common unit – diluted	$(0.49)	$0.86	$0.35
Subordinated unit – basic and diluted	$(0.44)	$0.79	$0.35
Weighted-average limited partner units outstanding (Note 9):			
Common units – basic	33,311	26,951	24,412
Common units – diluted	33,311	27,101	24,544
Subordinated units – basic and diluted	24,410	24,410	24,410
Cash distributions declared and paid per common unit	$2.040	$1.725	

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

75

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Membership interests	Total
	(In thousands)					
Membership interests, January 1, 2012	$—	$—	$—	$—	$640,818	$640,818
Net income	8,631	8,631	352	1,271	24,112	42,997
SMLP LTIP unit-based compensation	269	—	—	—	—	269
Class B membership interest unit-based compensation	(186)	—	—	—	1,793	1,607
Net assets retained by the Predecessor	—	—	—	—	(4,417)	(4,417)
Contribution of net assets to SMLP	211,938	430,498	19,870	—	(662,306)	—
Issuance of common units, net of offering costs	262,382	—	—	—	—	262,382
Distribution of proceeds from offering	(64,178)	(58,960)	—	—	—	(123,138)
Consolidation of Red Rock Gathering net assets	—	—	—	206,694	—	206,694
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	500	—	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	2,536	—	2,536
Partners' capital, December 31, 2012	418,856	380,169	20,222	211,001	—	1,030,248

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS
(continued)

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, December 31, 2012	418,856	380,169	20,222	211,001	1,030,248
Net income	22,311	20,238	1,035	9,720	53,304
SMLP LTIP unit-based compensation	2,999	—	—	—	2,999
Distributions to unitholders	(46,286)	(42,107)	(1,803)	—	(90,196)
Consolidation of Bison Midstream net assets	—	—	—	303,168	303,168
Contribution from Summit Investments to Bison Midstream	—	—	—	2,229	2,229
Purchase of Bison Midstream	47,936	—	978	(248,914)	(200,000)
Contribution of net assets from Summit Investments in excess of consideration paid for Bison Midstream	28,558	26,846	1,131	(56,535)	—
Issuance of units in connection with the Mountaineer Acquisition	98,000	—	2,000	—	100,000
Class B membership interest unit-based compensation	17	—	—	490	507
Repurchase of DFW Net Profits Interests	(5,859)	(5,859)	(239)	—	(11,957)
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	738	738
Capitalized interest allocated to Red Rock Gathering projects from Summit Investments	—	—	—	496	496
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	10,149	10,149
Capital expenditures paid by Summit Investments on behalf of Red Rock Gathering	—	—	—	52	52
Partners' capital, December 31, 2013	566,532	379,287	23,324	232,594	1,201,737

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS
(continued)

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, December 31, 2013	566,532	379,287	23,324	232,594	1,201,737
Net (loss) income	(15,948)	(11,169)	3,125	2,828	(21,164)
SMLP LTIP unit-based compensation	4,696	—	—	—	4,696
Distributions to unitholders	(67,658)	(49,796)	(4,770)	—	(122,224)
Tax withholdings on vested SMLP LTIP awards	(656)	—	—	—	(656)
Issuance of common units, net of offering costs	197,806	—	—	—	197,806
Contribution from general partner	—	—	4,235	—	4,235
Purchase of Red Rock Gathering	—	—	—	(307,941)	(307,941)
Excess of purchase price over acquired carrying value of Red Rock Gathering	(37,910)	(26,891)	(1,323)	66,124	—
Assets contributed to Red Rock Gathering from Summit Investments	2,426	1,722	85	—	4,233
Cash advance from Summit Investments to contributed subsidiaries	—	—	—	1,982	1,982
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	4,413	4,413
Repurchase of SMLP LTIP units	(228)	—	—	—	(228)
Partners' capital, December 31, 2014	$649,060	$293,153	$24,676	$—	$966,889

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,		
	2014	2013	2012
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	$(21,164)	$53,304	$42,997
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	83,934	70,994	36,866
Amortization of deferred loan costs	2,770	2,246	1,458
Unit-based compensation	4,696	3,506	1,876
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Purchase accounting adjustment	(1,185)	—	—
Pay-in-kind interest on promissory notes payable to Sponsors	—	—	5,426
Changes in operating assets and liabilities:			
Accounts receivable	(15,579)	(18,605)	(8,174)
Due to/from affiliate	(883)	1,427	(773)
Trade accounts payable	(970)	(3,419)	(2,536)
Change in deferred revenue	26,378	16,685	9,994
Ad valorem taxes payable	342	(11)	3,125
Accrued interest	6,714	12,128	(484)
Other, net	2,736	2,321	(383)
Net cash provided by operating activities	147,935	140,689	89,392
Cash flows from investing activities:			
Capital expenditures	(128,325)	(109,376)	(77,296)
Proceeds from asset sales	325	585	—
Acquisition of gathering systems	(10,872)	(210,000)	—
Acquisition of gathering systems from affiliate	(305,000)	(200,000)	—
Net cash used in investing activities	(443,872)	(518,791)	(77,296)

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(continued)

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	(122,224)	(90,196)	—
Borrowings under revolving credit facility	237,295	380,950	213,000
Repayments under revolving credit facility	(315,295)	(294,180)	(160,770)
Deferred loan costs	(5,320)	(10,608)	(3,344)
Tax withholdings on vested SMLP LTIP awards	(656)	—	—
Proceeds from issuance of common units, net	197,806	—	263,125
Contribution from general partner	4,235	2,229	—
Cash advance from Summit Investments to contributed subsidiaries, net	1,982	738	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	4,413	10,149	2,536
Issuance of senior notes	300,000	300,000	—
Issuance of units to affiliate in connection with the Mountaineer Acquisition	—	100,000	—
Repurchase of equity-based compensation awards	(228)	(11,957)	—
Red Rock Gathering cash contributed by Summit Investments	—	—	1,097
Repayment of promissory notes payable to Sponsors	—	—	(209,230)
Distributions to Sponsors	—	—	(123,138)
Net cash provided by (used in) financing activities	302,008	387,125	(16,224)
Net change in cash and cash equivalents	6,071	9,023	(4,128)
Cash and cash equivalents, beginning of period	20,357	11,334	15,462
Cash and cash equivalents, end of period	$26,428	$20,357	$11,334
Supplemental Cash Flow Disclosures:			
Cash interest paid	$31,524	$9,016	$8,283
Less: capitalized interest	3,172	4,705	2,784
Interest paid (net of capitalized interest)	$28,352	$4,311	$5,499
Cash paid for taxes	$—	$660	$650
Noncash Investing and Financing Activities:			
Capital expenditures in trade accounts payable (period-end accruals)	$6,359	$16,470	$8,523
Excess of purchase price over acquired carrying value of Red Rock Gathering	66,124	—	—
Red Rock Gathering working capital adjustment	(2,941)	—	—
Assets contributed to Red Rock Gathering from Summit Investments	4,233	—	—
Issuance of units to affiliate to partially fund the Bison Drop Down	—	48,914	—
Contribution of net assets from Summit Investments in excess of consideration paid for Bison Midstream	—	56,535	—
Capitalized interest allocated to Red Rock Gathering projects from Summit Investments	—	496	—
Capital expenditures paid by Summit Investments on behalf of Red Rock Gathering	—	52	—
Pay-in-kind interest on promissory notes payable to Sponsors	—	—	6,337
Net assets retained by the Predecessor	—	—	4,417

Deferred initial public offering costs in trade accounts payable	—	—	743

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

Table of Contents

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS
1. ORGANIZATION, BUSINESS OPERATIONS AND BASIS OF PRESENTATION
Organization. Summit Midstream Partners, LP ("SMLP" or the "Partnership"), a Delaware limited partnership, was formed in May 2012 and began operations in October 2012 in connection with its initial public offering ("IPO") of common limited partner units. SMLP is a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America.
Effective with the completion of its IPO on October 3, 2012, SMLP had a 100% ownership interest in Summit Midstream Holdings, LLC ("Summit Holdings") which had a 100% ownership interest in both DFW Midstream Services LLC ("DFW Midstream") and Grand River Gathering, LLC ("Grand River Gathering" or the "Legacy Grand River" system).
On June 4, 2013, the Partnership acquired all of the membership interests of Bison Midstream, LLC ("Bison Midstream") from a wholly owned subsidiary of Summit Midstream Partners, LLC ("Summit Investments") (the "Bison Drop Down"), and thereby acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Bakken Shale Play in Mountrail and Burke counties in North Dakota (the "Bison Gas Gathering system").
Prior to the Bison Drop Down, on February 15, 2013, Summit Investments acquired Bear Tracker Energy, LLC ("BTE"), which was subsequently renamed Meadowlark Midstream Company, LLC ("Meadowlark Midstream"). The Bison Gas Gathering system was carved out from Meadowlark Midstream in connection with the Bison Drop Down. As such, it was determined to be a transaction among entities under common control.
On June 21, 2013, Mountaineer Midstream Company, LLC ("Mountaineer Midstream"), a newly formed, wholly owned subsidiary of the Partnership, acquired certain natural gas gathering pipeline and compression assets in the Marcellus Shale Play in Doddridge and Harrison counties, West Virginia from an affiliate of MarkWest Energy Partners, L.P. ("MarkWest") (the "Mountaineer Acquisition"). In December 2013, Mountaineer Midstream was merged into DFW Midstream.
In October 2012, Summit Investments acquired ETC Canyon Pipeline, LLC ("Canyon") from a subsidiary of Energy Transfer Partners, L.P. The Canyon gathering and processing assets were contributed to Red Rock Gathering Company, LLC ("Red Rock Gathering"), a newly formed, wholly owned subsidiary of Summit Investments. Red Rock Gathering gathers and processes natural gas and natural gas liquids in the Piceance Basin in western Colorado and eastern Utah. On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering from a subsidiary of Summit Investments (the "Red Rock Drop Down"). As such, it was determined to be a transaction among entities under common control. Concurrent with the closing of the Red Rock Drop Down, SMLP contributed its interest in Red Rock Gathering to Grand River Gathering.
Summit Investments is a Delaware limited liability company and the predecessor for accounting purposes of SMLP. Summit Investments was formed and began operations in September 2009. Through August 2011, Summit Investments was wholly owned by Energy Capital Partners II, LLC and its parallel and co-investment funds (collectively, "Energy Capital Partners"). In August 2011, Energy Capital Partners sold an interest in Summit Investments to a subsidiary of GE Energy Financial Services, Inc. ("GE Energy Financial Services"). In June 2014, GE Energy Financial Services exchanged 100% of its Class A membership interests in Summit Investments for a new class of membership interests, structured as Class C Preferred interests. As a result, GE Energy Financial Services is no longer a Class A member of Summit Investments. Consequently, we refer to Energy Capital Partners and GE Energy Financial Services as our "Sponsors" for the period from August 17, 2011 until June 17, 2014, and we refer to Energy Capital Partners as our sole "Sponsor" subsequent to June 2014.
In March 2013, Summit Investments contributed the ownership of its SMLP common and subordinated units along with its 2% general partner interest in SMLP (including the incentive distribution rights ("IDRs") in respect of SMLP) to Summit Midstream Partners Holdings, LLC ("SMP Holdings") in exchange for a continuing 100% interest in SMP Holdings. As of December 31, 2014, Summit Investments, through a wholly owned subsidiary, held 5,293,571 SMLP common units, all of our subordinated units, all of our general partner units representing a 2% general partner interest

in SMLP and all of our IDRs.

SMLP is managed and operated by the board of directors and executive officers of Summit Midstream GP, LLC (the "general partner"). Summit Investments, as the ultimate owner of our general partner, controls SMLP and has the right to appoint the entire board of directors of our general partner, including our independent directors. SMLP's operations are conducted through, and our operating assets are owned by, various wholly-owned operating subsidiaries. However, neither SMLP nor its subsidiaries have any employees. The general partner has the sole responsibility for providing the personnel necessary to conduct SMLP's operations, whether through directly hiring employees or by obtaining the services of personnel employed by others, including Summit Investments. All of the personnel that conduct SMLP's business are employed by the general partner and its subsidiaries, but these individuals are sometimes referred to as our employees.

References to the "Company," "we," or "our," when used for dates or periods ended on or after the IPO, refer collectively to SMLP and its subsidiaries. References to the "Company," "we," or "our," when used for dates or periods ended prior to the IPO, refer collectively to Summit Investments and its subsidiaries.

Initial Public Offering. On October 3, 2012, SMLP completed its IPO and the following transactions occurred:

- Summit Investments conveyed an interest in Summit Holdings to our general partner as a capital contribution;
- our general partner conveyed its interest in Summit Holdings to SMLP in exchange for (i) a continuation of its 2% general partner interest in SMLP, represented by 996,320 general partner units, and (ii) SMLP incentive distribution rights, or IDRs;
- Summit Investments conveyed its remaining interest in Summit Holdings to SMLP in exchange for (i) 10,029,850 common units (net of the impact of selling 1,875,000 common units to the public for cash in connection with the exercise of the underwriters' option to purchase additional common units), representing a 20.1% limited partner interest in SMLP, (ii) 24,409,850 subordinated units, representing a 49.0% limited partner interest in SMLP, and (iii) the right to receive \$88.0 million in cash as reimbursement for certain capital expenditures made with respect to the contributed assets;
- pursuant to its long-term incentive plan, SMLP granted 5,000 common units (in the aggregate) to two of its directors and 125,000 phantom units, with distribution equivalent rights, to certain employees;
- SMLP issued 14,375,000 common units to the public (including 1,875,000 additional common units sold out of the common units originally allocated to Summit Investments) representing a 28.9% limited partner interest in SMLP; and
- SMLP used the proceeds, net of underwriters' fees, from the IPO of approximately \$269.4 million to (i) repay \$140.0 million outstanding under the revolving credit facility; (ii) make cash distributions to Summit Investments of (a) \$88.0 million to reimburse Summit Investments for certain capital expenditures it incurred with respect to assets it contributed to us and (b) \$35.1 million representing the funds received in connection with the underwriters exercising their option to purchase additional common units; and (iii) pay IPO expenses of approximately \$6.3 million.

Business Operations. We provide natural gas gathering, treating and processing services pursuant to primarily long-term and fee-based, natural gas gathering agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. Our gathering and processing systems and the unconventional resource basins in which they operate as of December 31, 2014 were as follows:

- Mountaineer Midstream – the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream – the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- DFW Midstream – the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Grand River Gathering – the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

Our operating subsidiaries are DFW Midstream (which includes the Mountaineer Midstream gathering system), Bison Midstream and Grand River Gathering. All of our operating subsidiaries are midstream energy companies focused on the development, construction and operation of natural gas gathering and processing systems.

Basis of Presentation and Principles of Consolidation. We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). These principles are established by the Financial Accounting Standards Board. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the balance sheet dates, including fair value measurements,

Table of Contents

the reported amounts of revenue and expense, and the disclosure of contingencies. Although management believes these estimates are reasonable, actual results could differ from its estimates.

We conduct our operations in the midstream sector through four reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin, which is served by Bison Midstream;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River. Grand River is composed of the Legacy Grand River and Red Rock Gathering systems.

The assets of our reportable segments consist of natural gas gathering and processing systems and related plant and equipment. 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.

For the purposes of the consolidated financial statements, SMLP's results of operations reflect the Partnership's operations subsequent to the IPO and the results of the Predecessor for the period prior to the IPO. The consolidated financial statements also reflect the results of operations of: (i) Red Rock Gathering since October 23, 2012, (ii) Bison Midstream since February 16, 2013 and (iii) Mountaineer Midstream since June 22, 2013. SMLP recognized its acquisitions of Red Rock Gathering and Bison Midstream at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of the purchase price paid by SMLP over Summit Investments' net investment in Red Rock Gathering was recognized as a reduction to partners' capital. The excess of Summit Investments' net investment in Bison Midstream over the purchase price paid by SMLP was recognized as an addition to partners' capital. Due to the common control aspect, the Red Rock Drop Down and the Bison Drop Down were accounted for by the Partnership on an "as-if pooled" basis for the periods during which common control existed. The consolidated financial statements include the assets, liabilities, and results of operations of SMLP or the Predecessor and their respective wholly owned subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Accounts Receivable. Accounts receivable relate to gathering and other services provided to our natural gas producer customers and other counterparties. To the extent we doubt the collectability of our accounts receivable, we recognize an allowance for doubtful accounts. We did not experience any non-payments during the three-year period ended December 31, 2014. As a result, we did not recognize an allowance for doubtful accounts as of December 31, 2014 and 2013.

Other Current Assets. Other current assets primarily consist of the current portion of prepaid expenses that are charged to expense over the period of benefit or the life of the related contract.

Property, Plant, and Equipment. We record property, plant, and equipment at historical cost of construction or fair value of the assets at acquisition. We capitalize expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, we recognize expenditures as an expense as incurred. We capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress. Prior to the Red Rock Drop Down, a subsidiary of Summit Investments incurred interest expense related to certain Red Rock Gathering capital projects. The associated interest expense was allocated to Red Rock Gathering as a noncash equity contribution and capitalized into the basis of the asset.

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. We record depreciation on a straight-line basis over an asset's estimated useful life. We base our estimates for useful life on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances, and historical data concerning useful lives of similar assets.

Upon sale, retirement or other disposal, we remove the carrying value of an asset and its accumulated depreciation from our balance sheet and recognize the related gain or loss, if any.
Accrued capital expenditures are reflected in trade accounts payable.

Table of Contents

Asset Retirement Obligations. We record a liability for asset retirement obligations only if and when a future asset retirement obligation with a determinable life is identified. As of December 31, 2014 and 2013, we evaluated whether any future asset retirement obligations existed. For identified asset retirement obligations, we then evaluated whether the expected retirement date and the related costs of retirement could be estimated. In performing this evaluation, we concluded that our natural gas gathering and processing assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Because we did not have sufficient information to reasonably estimate the amount or timing of such obligations and we have no current plan to discontinue use of any significant assets, we did not provide for any asset retirement obligations as of December 31, 2014 or 2013.

Intangible Assets and Noncurrent Liability. Upon the acquisition of DFW Midstream, certain of our gas gathering contracts were deemed to have above-market pricing structures while another was deemed to have pricing that was below market. We have recognized the contracts that were above market at acquisition as favorable gas gathering contracts. We have recognized the contract that was deemed to be below market as a noncurrent liability. We amortize these intangibles on a units-of-production basis over the estimated useful life of the contract. We define useful life as the period over which the contract is expected to contribute directly or indirectly to our future cash flows. The related contracts have original terms ranging from 10 years to 20 years. We recognize the amortization expense associated with these intangible assets and liability in amortization of favorable and unfavorable contracts.

For our other gas gathering contracts, we amortize contract intangible assets over the period of economic benefit based upon the expected revenues over the life of the contract. The useful life of these contracts ranges from 10 years to 25 years. We recognize the amortization expense associated with these intangible assets in depreciation and amortization expense.

We have right-of-way intangible assets associated with city easements and easements granted within existing rights-of-way. We amortize these intangible assets over the shorter of the contractual term of the rights-of-way or the estimated useful life of the gathering system. The contractual terms of the rights-of-way range from 20 years to 30 years. The estimated useful life of our gathering systems is 30 years. We recognize the amortization expense associated with these intangible assets in depreciation and amortization expense.

Impairment of Long-Lived Assets. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If we conclude that an asset’s carrying value will not be recovered through future cash flows, we recognize an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. We determine fair value using an income approach in which we discount the asset’s expected future cash flows to reflect the risk associated with achieving the underlying cash flows. During the three-year period ended December 31, 2014, we concluded that none of our long-lived assets had been impaired, except as discussed in Notes 4 and 5.

Goodwill. Goodwill represents consideration paid in excess of the fair value of the net identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on September 30. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We test goodwill for impairment using a two-step quantitative test. In the first step, we compare the fair value of the reporting unit to its carrying value, including goodwill. If the reporting unit’s fair value exceeds its carrying amount, we conclude that the goodwill of the reporting unit has not been impaired and no further work is performed. If we determine that the reporting unit’s carrying value exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting unit to its implied fair value. If we determine that the carrying amount of a reporting unit's goodwill exceeds its implied fair value, we recognize the excess of the carrying value over the implied fair value as an impairment loss.

Other Noncurrent Assets. Other noncurrent assets primarily consist of external costs incurred in connection with the issuance of our senior notes and the closing of our revolving credit facility and related amendments. We capitalize and then amortize these deferred loan costs over the life of the respective debt instrument. We recognize amortization of deferred loan costs in interest expense.

Derivative Contracts. We have commodity price exposure related to our sale of the physical natural gas we retain from our DFW Midstream customers, and our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system. Our gas gathering agreements with our DFW Midstream customers permit us to retain a certain quantity of natural gas that we gather to offset the power costs we incur to operate our electric-

Table of Contents

drive compression assets. We manage this direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices 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 retainage sales.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections and hedge accounting designations, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. We have designated these contracts as normal under the normal purchase and sale exception under the accounting standards for derivatives. We do not enter into risk management contracts for speculative purposes.

Fair Value of Financial Instruments. The fair-value-measurement standard under GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which the inputs are observable. The three levels of the fair value hierarchy are as follows:

- Level 1. Inputs represent quoted prices in active markets for identical assets or liabilities;
- Level 2. Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs); and
- Level 3. Inputs that are not observable from objective sources, such as management’s internally developed assumptions used in pricing an asset or liability (for example, an internally developed present value of future cash flows model that underlies management's fair value measurement).

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the balance sheet approximates fair value due to their short-term maturities.

A summary of the estimated fair value of our debt financial instruments follows.

	December 31, 2014		December 31, 2013	
	Carrying value	Estimated fair value (Level 2)	Carrying value	Estimated fair value (Level 2)
	(In thousands)			
Revolving credit facility	$208,000	$208,000	$286,000	$286,000
5.5% Senior notes	300,000	281,750	—	—
7.5% Senior notes	300,000	306,750	300,000	314,625

The revolving credit facility’s carrying value on the balance sheet is its fair value due to its floating interest rate. The fair value for the senior notes is based on an average of nonbinding broker quotes as of December 31, 2014 and December 31, 2013. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the senior notes.

Nonfinancial assets and liabilities initially measured at fair value include those acquired and assumed in connection with third-party business combinations.

Commitments and Contingencies. We record accruals for loss contingencies when we determine that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events.

Revenue Recognition. We generate the majority of our revenue from the natural gas gathering, treating and processing services that we provide to our natural gas producer customers. We also generate revenue from our marketing of natural gas and NGLs. We realize revenues by receiving fees from our producer customers or by selling the residue natural gas and NGLs.

We recognize revenue earned from fee-based gathering, treating and processing services in gathering services and other fees revenue. We also earn revenue from the sale of physical natural gas purchased from our customers

Table of Contents

under percentage-of-proceeds and keep-whole arrangements. These revenues are recognized in natural gas, NGLs and condensate sales and other with corresponding expense recognition in cost of natural gas and NGLs. We sell substantially all of the natural gas that we retain from our DFW Midstream customers to offset the power expenses of the electric-driven compression on the DFW Midstream system. We also sell condensate retained from our gathering services at Grand River Gathering. Revenues from the retainage of natural gas and condensate are recognized in natural gas, NGLs and condensate sales and other; the associated expense is included in operation and maintenance expense. Certain customers reimburse us for costs we incur on their behalf. We record costs incurred and reimbursed by our customers on a gross basis.

We recognize revenue when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price is fixed or determinable, and (iv) collectability is reasonably assured.

We obtain access to natural gas and provide services principally under contracts that contain one or more of the following arrangements:

- Fee-based arrangements. Under fee-based arrangements, we receive a fee or fees for one or more of the following services: natural gas gathering, treating, and/or processing. Fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead, or other receipt points, at a settled price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The margins earned are directly related to the volume of natural gas that flows through the system.
- Percent-of-proceeds arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat the natural gas, process the natural gas and/or sell the natural gas to a third party for processing. We then remit to our producers an agreed-upon percentage of the actual proceeds received from sales of the residue natural gas and NGLs. Certain of these arrangements may also result in returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. The margins earned are directly related to the volume of natural gas that flows through the system and the price at which we are able to sell the residue natural gas and NGLs.
- Keep-Whole. Under keep-whole arrangements, after processing we keep 100% of the NGLs produced, and the processed natural gas, or value of the natural gas, is returned to the producer. Since some of the natural gas is used and removed during processing, we compensate the producer for the amount of natural gas used and removed in processing by supplying additional natural gas or by paying an agreed-upon value for the natural gas utilized. These arrangements have commodity price exposure for us because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

Certain of our natural gas gathering or processing agreements provide for a monthly, quarterly or annual MVC. Under these MVCs, our customers agree to ship a minimum volume of natural gas 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 contract 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 periods to the extent that such customer's throughput volumes in subsequent periods 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 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 natural gas gathering agreement.

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.

Table of Contents

Unit-Based Compensation. For awards of unit-based compensation, we determine a grant date fair value and recognize the related compensation expense, in the statement of operations over the vesting period of the respective awards.

Income Taxes. Since we are structured as a partnership, we are generally not subject to federal and state income taxes, except as noted below. As a result, our unitholders or members are individually responsible for paying federal and state income taxes on their share of our taxable income. Net income or loss for financial statement purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and the financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement.

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to a franchise tax (the "Texas Margin Tax"). The Texas Margin Tax has the characteristics of an income tax because it is determined by applying a tax rate to a tax base that considers both revenues and expenses. Our financial statements reflect provisions for these tax obligations.

In 2014, the Company elected to apply changes to the determination of cost of goods sold for the Texas Margin Tax which permits the use of accelerated depreciation allowed for federal income tax purposes. As a result of this change, we recognized a $1.0 million deferred tax liability and current income tax expense for the year ended December 31, 2014 was reduced by $0.3 million. The associated deferred tax liability of $1.3 million is included in other noncurrent liabilities at December 31, 2014.

Earnings Per Unit ("EPU"). We present earnings or loss per limited partner unit only for periods subsequent to the IPO. Prior to the IPO, Summit Investments' members held membership interests and not units.

We determine EPU by dividing the net income or loss that is attributed, in accordance with the net income and loss allocation provisions of the partnership agreement, to the common and subordinated unitholders under the two-class method, after deducting the general partner's 2% interest in net income or loss and any payments to the general partner in connection with their IDRs, by the weighted-average number of common and subordinated units outstanding during the years ended December 31, 2014 and 2013, and the period from October 1, 2012 to December 31, 2012. Diluted earnings or loss per limited partner unit reflects the potential dilution that could occur if securities or other agreements to issue common units, such as unit-based compensation, were exercised, settled or converted into common units. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted earnings per limited partner unit calculation, the impact is reflected by applying the treasury stock method.

Comprehensive Income. Comprehensive income is the same as net income or loss for all periods presented.

Environmental Matters. We are subject to various federal, state and local laws and regulations relating to the protection of the environment. Although we believe that we are in material compliance with applicable environmental regulations, the risk of costs and liabilities are inherent in pipeline ownership and operation. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. There are no such material liabilities in the accompanying financial statements at December 31, 2014 or 2013. However, we can provide no assurance that significant costs and liabilities will not be incurred by the Partnership in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters.

Recent Accounting Pronouncements. Accounting standard setters frequently issue new or revised accounting rules. We review new pronouncements to determine the impact, if any, on our financial statements. There are currently no recent pronouncements that have been issued that we believe will materially affect our financial statements, except as noted below.

In May 2014, the Financial Accounting Standards Board released a joint revenue recognition standard, Accounting Standards Update No. 2014-09 ("ASC Update 2014-09"). Under ASC Update 2014-09, revenue will be recognized under a five-step model: (i) identify the contract with the customer; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to performance obligations; and (v) recognize revenue when (or as) the partnership satisfies a performance obligation. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, and interim and annual periods thereafter. Early adoption is not permitted. We are currently in the process of evaluating the impact of this update.

Table of Contents

3. SEGMENT INFORMATION

In the fourth quarter of 2014, we discontinued the aggregation of all of our operating segments. As of December 31, 2014, our reportable segments are the Marcellus Shale, the Williston Basin, the Barnett Shale and the Piceance Basin. The Piceance Basin reportable segment aggregates our Legacy Grand River and Red Rock Gathering operating segments. Each of our reportable segments provide midstream services in a specific geographic area. Corporate represents those revenues and expenses that are not specifically attributable to a reportable segment, not individually reportable, or that have not been allocated to our reportable segments. The accounting policies of the reportable segments and Corporate are the same as those described in the summary of significant accounting policies.

The following table presents assets by reportable segment as of December 31.

	December 31,	
	2014	2013
	(In thousands)	
Assets:		
Marcellus Shale	$243,884	$214,379
Williston Basin	311,041	337,610
Barnett Shale	428,935	431,578
Piceance Basin	872,437	876,969
Total reportable segment assets	1,856,297	1,860,536
Corporate	38,577	23,203
Total assets	$1,894,874	$1,883,739

We assess the performance of our reportable segments based on segment adjusted EBITDA. We define segment adjusted EBITDA as total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) depreciation and amortization, (iii) adjustments related to MVC shortfall payments, (iv) impairments and (v) other noncash expenses or losses, less other noncash income or gains. Segment adjusted EBITDA excludes the effect of allocated corporate expenses, such as certain general and administrative expenses (including compensation-related expenses and professional services fees) interest expense and income tax expense.

The following table presents segment adjusted EBITDA by reportable segment.

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Reportable segment adjusted EBITDA:			
Marcellus Shale	$15,940	$6,333	
Williston Basin	20,422	16,865	
Barnett Shale	60,528	69,473	$63,670
Piceance Basin	107,953	80,941	53,179
Total reportable segment adjusted EBITDA	$204,843	$173,612	$116,849

Table of Contents

The following table presents a reconciliation of income before income taxes to total reportable segment adjusted EBITDA.

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Reconciliation of Income Before Income Taxes to Segment Adjusted EBITDA:			
Income before income taxes	$(20,533)	$54,033	$43,679
Add:			
Interest expense and affiliated interest expense	40,159	19,173	12,766
Depreciation and amortization	82,990	69,962	36,674
Amortization of favorable and unfavorable contracts	944	1,032	192
Allocated corporate expenses	11,065	8,773	10,903
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	4,696	3,506	1,876
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Less:			
Interest income	4	5	9
Impact of purchase price adjustments	1,185	—	—
Total reportable segment adjusted EBITDA	$204,843	$173,612	$116,849

Table of Contents

The following table summarizes details by reportable segment for the years ended December 31.

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Revenues:			
Marcellus Shale	$22,694	$9,588	
Williston Basin	62,454	50,735	
Barnett Shale	93,001	105,324	$93,453
Piceance Basin	152,537	127,273	81,961
Total reportable segments	330,686	292,920	175,414
Corporate	—	—	(991)
Total revenues	$330,686	$292,920	$174,423
Depreciation and amortization:			
Marcellus Shale	$7,648	$3,998	
Williston Basin	18,132	16,057	
Barnett Shale	15,657	13,929	$12,078
Piceance Basin	40,965	35,527	24,310
Total reportable segments	82,402	69,511	36,388
Corporate	588	451	286
Total depreciation and amortization	$82,990	$69,962	$36,674
Other income:			
Marcellus Shale	$—	$—	
Williston Basin	—	—	
Barnett Shale	—	—	$—
Piceance Basin	1,185	—	—
Total reportable segments	1,185	—	—
Corporate	4	5	9
Total other income	$1,189	$5	$9
Capital expenditures:			
Marcellus Shale	$33,866	$1,822	
Williston Basin	46,927	26,381	
Barnett Shale	14,567	29,534	$39,588
Piceance Basin	32,505	50,709	36,899
Total reportable segments	127,865	108,446	76,487
Corporate	460	930	809
Total capital expenditures	$128,325	$109,376	$77,296

Table of Contents

4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment, net were as follows:

	Useful lives (In years)	December 31, 2014	2013
		(Dollars in thousands)	
Natural gas gathering and processing systems	30	$881,235	$744,359
Compressor stations and compression equipment	30	410,906	380,000
Construction in progress	n/a	33,177	83,765
Other	4-15	27,345	21,304
Total		1,352,663	1,229,428
Less: accumulated depreciation		117,011	71,347
Property, plant, and equipment, net		$1,235,652	$1,158,081

During the fourth quarter of 2014, we reviewed certain property, plant and equipment balances associated with a compressor station project on our DFW Midstream system that was terminated and wrote off approximately $5.5 million of costs. The net impact of this action is reflected in long-lived asset impairment on the statement of operations. We also sold certain fixed assets during the fourth quarter of 2014. The net impact of these transactions is reflected in loss on asset sales, net on the statement of operations.

Also during the fourth quarter of 2014, prices for natural gas, NGLs and crude oil continued to decline such that we identified a need to evaluate the goodwill associated with the Bison Midstream system. In connection with this evaluation, we also evaluated the property, plant and equipment and intangible assets associated with the Bison Midstream system for impairment and concluded that no impairment was necessary.

Construction in progress is depreciated consistent with its applicable asset class once it is placed in service.

Depreciation expense related to property, plant, and equipment and capitalized interest were as follows:

	Year ended December 31, 2014	2013	2012
	(In thousands)		
Depreciation expense	$45,734	$36,745	$22,422
Capitalized interest	3,172	4,705	2,784

5. IDENTIFIABLE INTANGIBLE ASSETS, NONCURRENT LIABILITY AND GOODWILL

Identifiable Intangible Assets and Noncurrent Liability. Identifiable intangible assets and the noncurrent liability, which are subject to amortization, were as follows:

	December 31, 2014			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(8,056)	$16,139
Contract intangibles	12.5	426,464	(75,713)	350,751
Rights-of-way	24.2	112,393	(12,417)	99,976
Total amortizable intangible assets		$563,052	$(96,186)	$466,866
Unfavorable gas gathering contract	10.0	$10,962	$(5,385)	$5,577

Table of Contents

	December 31, 2013			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(6,315)	$17,880
Contract intangibles	12.5	426,464	(43,158)	383,306
Rights-of-way	24.3	108,706	(7,715)	100,991
Total amortizable intangible assets		$559,365	$(57,188)	$502,177
Unfavorable gas gathering contract	10.0	$10,962	$(4,588)	$6,374

We recognized amortization expense in revenues as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Amortization expense – favorable gas gathering contracts	$(1,741)	$(2,078)	$(1,715)
Amortization expense – unfavorable gas gathering contract	797	1,046	1,524
Amortization of favorable and unfavorable contracts	$(944)	$(1,032)	$(191)

During the fourth quarter of 2014, prices for natural gas and crude oil continued to decline such that we identified a need to evaluate the goodwill associated with the Bison Midstream system, as discussed below. In connection with this evaluation, we also evaluated the intangible assets and property, plant and equipment associated with the Bison Midstream system for impairment and concluded that no impairment was necessary.

We recognized amortization expense in costs and expenses as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Amortization expense – contract intangibles	$32,554	$28,654	$12,642
Amortization expense – rights-of-way	4,702	4,563	1,610

The estimated aggregate annual amortization of intangible assets and noncurrent liability expected to be recognized as of December 31, 2014 for each of the five succeeding fiscal years follows.

	Assets	Liability
	(In thousands)	
2015	$41,882	$698
2016	41,846	924
2017	40,697	1,047
2018	40,301	1,123
2019	40,247	957

Table of Contents

Goodwill. Recorded goodwill is related to the original acquisitions of the Grand River Gathering, Bison Midstream and Mountaineer Midstream systems. A rollforward of goodwill by reportable segment and in total follows.

	Piceance Basin	Williston Basin	Marcellus Shale	Total
	(In thousands)			
Goodwill, December 31, 2012	$45,478	$—	$—	$45,478
Goodwill recognized in connection with the Bison Drop Down	—	54,199	—	54,199
Goodwill preliminarily recognized in connection with the Mountaineer Acquisition	—	—	18,089	18,089
Goodwill adjustment recognized in connection with finalizing accounting for the Mountaineer Acquisition and other	—	—	(1,878)	(1,878)
Goodwill, December 31, 2013	45,478	54,199	16,211	115,888
Goodwill impairment (1)	—	(54,199)	—	(54,199)
Goodwill, December 31, 2014	$45,478	$—	$16,211	$61,689

(1) Balance represents the cumulative goodwill impairment as of December 31, 2014.

Annual Impairment Evaluation. As discussed in Note 2, we evaluate goodwill for impairment annually on September 30. We performed our annual goodwill impairment testing as of September 30, 2014 using a combination of the income and market approaches. The results thereof follow:

- We determined that the fair value of the Grand River Gathering reporting unit, as included in the Piceance Basin reportable segment, substantially exceeded its carrying value, including goodwill as of September 30, 2014.
- We determined that the fair value of the Mountaineer Midstream reporting unit, as included in the Marcellus Shale reportable segment, substantially exceeded its carrying value, including goodwill as of September 30, 2014.
- We determined that the fair value of the Bison Midstream reporting unit, as included in the Williston Basin reportable segment, exceeded its carrying value, including goodwill, as of September 30, 2014. However, it did not exceed its carrying value, including goodwill, by a substantial amount.
- Because the fair values of these reporting units exceeded their carrying values, including goodwill, there were no associated impairments of goodwill in connection with our 2014 annual goodwill impairment test.

Fourth Quarter 2014 Goodwill Impairment. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value, including goodwill. During the latter part of the fourth quarter of 2014, the declines in prices for natural gas, NGLs and crude oil accelerated, negatively impacting producers in each of our areas of operation. As a result, we considered whether the goodwill associated with our Grand River Gathering, Mountaineer Midstream and Bison Midstream reporting units could have been impaired. Our assessments related to Grand River Gathering and Mountaineer Midstream did not result in an indication that the associated goodwill had been impaired.

Our assessment related to the Bison Midstream reporting unit did result in an indication that the associated goodwill could have been impaired. In connection therewith, we noted that a key Bison Midstream customer announced that it was delaying its previously announced drilling plans. The combined impact of (i) the price declines on revenues under its percent-of proceeds contracts and (ii) the Partnership's reduction in its forecasted volume assumption in response to the decline in our customer’s drilling plans increased the likelihood that the goodwill associated with the Bison Midstream reporting unit was impaired. As such, we concluded that a triggering event occurred during the fourth quarter of 2014 requiring that we test the goodwill associated with the Bison Midstream reporting unit for impairment.

To estimate the fair value of the Bison Midstream reporting unit, we utilized two valuation methodologies: the market approach and the income approach. Both of these approaches incorporate significant estimates and assumptions to calculate enterprise fair value for a reporting unit. The most significant estimates and assumptions inherent within these two valuation methodologies are:

- determination of the weighted-average cost of capital;

Table of Contents

- the selection of guideline public companies;
- market multiples;
- weighting of the income and market approaches;
- growth rates;
- commodity prices; and
- the expected levels of throughput volume gathered.

Changes in the above and other assumptions could materially affect the estimated amount of fair value for any of our reporting units.

The results of our step one goodwill impairment testing indicated that the fair value of the Bison Midstream reporting unit was below its carrying value, including goodwill. This result required that we perform step two of the goodwill impairment test. To perform step two, we first determined the fair values of the identifiable assets and liabilities. Significant assumptions utilized in the determination of the fair value of each reporting unit's individual assets and liabilities included the determination of discount rate and contributing asset charge utilized in our contract intangibles, expected levels of throughput volume and associated capital expenditures and commodity prices.

Our preliminary estimates of the fair values of the identified assets and liabilities calculated in the step two testing of the Bison Midstream reporting unit indicated that all of the associated goodwill had been impaired. As such, we recorded an estimated goodwill impairment of $54.2 million. This amount represents our best estimate of impairment pending the finalization of the fair value calculations, which we expect to finalize in the first quarter of 2015.

Our impairment determinations, in the context of (i) our annual impairment evaluation and (ii) our fourth quarter 2014 evaluation, involved significant assumptions and judgments, as discussed above. 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 models are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

6. DEFERRED REVENUE

The majority of our gas gathering agreements provide for a monthly, quarterly or annual MVC from our customers. If a customer's actual throughput volumes are less than its MVC for the applicable period, it must make a shortfall payment to us at the end of that contract month, quarter or year, as applicable. 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 gathering or processing fee. To the extent that a customer's actual throughput volumes are above or below its MVC for the applicable period, however, many of our gas gathering agreements contain provisions that can reduce or delay the cash flows that we expect to receive from our MVCs. These provisions include the following:

- To the extent that a customer's throughput volumes are less than its MVC for the applicable period and the customer makes a shortfall payment, it may be entitled to an offset in one or more subsequent periods to the extent that its throughput volumes in subsequent periods exceed its MVC for those periods. In such a situation, we would not receive gathering fees on throughput in excess of a customer's monthly or annual MVC (depending on the terms of the specific gas gathering agreement) to the extent that the customer had made a shortfall payment with respect to one or more preceding months or years (as applicable).
- To the extent that a customer's throughput volumes exceed its MVC in the applicable period, it may be entitled to apply the excess throughput against its aggregate MVC, thereby reducing the period for which its annual MVC applies. As a result of this mechanism, the weighted-average remaining period for which our MVCs apply will be less than the weighted-average of the original stated contract terms of our MVCs.
- To the extent that certain of our customers' throughput volumes exceed its MVC for the applicable period, there is a crediting mechanism that allows the customer to build a bank of credits that it can utilize in the future to reduce shortfall payments owed in subsequent periods, subject to expiration if there is no shortfall in subsequent periods. The period over which this credit bank can be applied to future shortfall payments varies, depending on the particular gas gathering agreement.

Table of Contents

A rollforward of current deferred revenue follows.

	Williston Basin (In thousands)	Barnett Shale	Piceance Basin	Total current
Current deferred revenue, January 1, 2012	$—	$—	$—	$—
Additions	—	865	—	865
Current deferred revenue, December 31, 2012	—	865	—	865
Additions	—	1,555	—	1,555
Less: revenue recognized due to expiration	—	865	—	865
Current deferred revenue, December 31, 2013	—	1,555	—	1,555
Additions	—	2,610	—	2,610
Less: revenue recognized due to expiration	—	1,555	—	1,555
Less: revenue recognized due to usage	—	233	—	233
Current deferred revenue, December 31, 2014	$—	$2,377	$—	$2,377

A rollforward of noncurrent deferred revenue follows.

	Williston Basin (In thousands)	Barnett Shale	Piceance Basin	Total noncurrent
Noncurrent deferred revenue, January 1, 2012	$—	$—	$1,770	$1,770
Additions	—	—	9,129	9,129
Noncurrent deferred revenue, December 31, 2012	—	—	10,899	10,899
Additions(1)	6,389	—	12,395	18,784
Noncurrent deferred revenue, December 31, 2013	6,389	—	23,294	29,683
Additions	10,743	—	14,813	25,556
Noncurrent deferred revenue, December 31, 2014	$17,132	$—	$38,107	$55,239

(1) Noncurrent includes amounts recognized in connection with the Bison Drop Down.

As of December 31, 2014, accounts receivable included $13.1 million of shortfall billings related to MVC arrangements that can be utilized to offset gathering fees in subsequent periods. Noncurrent deferred revenue at December 31, 2014 represents amounts that provide certain customers the ability to offset their gathering fees over a period up to seven years to the extent that the customer's throughput volumes exceeds its MVC.

7. LONG-TERM DEBT

Long-term debt consisted of the following:

	December 31, 2014 (In thousands)	2013
Variable rate senior secured revolving credit facility (2.67% at December 31, 2014 and 2.42% at December 31, 2013) due November 2018	$208,000	$286,000
5.50% Senior unsecured notes due August 2022	300,000	—
7.50% Senior unsecured notes due July 2021	300,000	300,000
Total long-term debt	$808,000	$586,000

Table of Contents

The aggregate amount of our debt maturities during each of the years after December 31, 2014 are as follows:

	Long-term debt (In thousands)
2015	$—
2016	—
2017	—
2018	208,000
2019	—
Thereafter	600,000
Total long-term debt	$808,000

Revolving Credit Facility. We have a senior secured revolving credit facility which allows for revolving loans, letters of credit and swingline loans (the "revolving credit facility"). The revolving credit facility has a $700.0 million borrowing capacity, matures in November 2018, and includes a $200.0 million accordion feature. It is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of Summit Holdings' and its subsidiaries' assets are pledged as collateral under the revolving credit facility. The revolving credit facility, and Summit Holdings' obligations, are guaranteed by SMLP and each of its subsidiaries.

Borrowings under the revolving credit facility bear interest at the London Interbank Offered Rate ("LIBOR") or an Alternate Base Rate ("ABR") plus an applicable margin ranging from 0.75% to 1.75% for ABR borrowings and 1.75% to 2.75% for LIBOR borrowings, with the commitment fee ranging from 0.30% to 0.50% in each case based on our relative leverage at the time of determination. At December 31, 2014, the applicable margin under LIBOR borrowings was 2.50%, the interest rate was 2.67% and the unused portion of the revolving credit facility totaled $492.0 million (subject to a commitment fee of 0.500%).

The revolving credit agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability to: (i) incur additional debt; (ii) make investments; (iii) engage in certain mergers, consolidations, acquisitions or sales of assets; (iv) enter into swap agreements and power purchase agreements; (v) enter into leases that would cumulatively obligate payments in excess of $30.0 million over any 12-month period; and (vi) prohibits the payment of distributions by Summit Holdings if a default then exists or would result therefrom, and otherwise limits the amount of distributions Summit Holdings can make. In addition, the revolving credit facility requires Summit Holdings to maintain a ratio of consolidated trailing 12-month earnings before interest, income taxes, depreciation and amortization ("EBITDA," as defined in the credit agreement) to net interest expense of not less than 2.5 to 1.0 (as defined in the credit agreement) and a ratio of total net indebtedness to consolidated trailing 12-month EBITDA of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to 270 days following certain acquisitions.

As of December 31, 2014, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during the year ended December 31, 2014.

Senior Notes. On July 15, 2014, Summit Holdings and its 100% owned finance subsidiary, Summit Midstream Finance Corp. ("Finance Corp.," together with Summit Holdings, the "Co-Issuers"), co-issued $300.0 million of 5.50% senior unsecured notes maturing August 15, 2022 (the "5.5% senior notes"). In June 2013, the Co-Issuers co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021 (the "7.5% senior notes").

SMLP and all of its subsidiaries other than the Co-Issuers (the "Guarantors") have fully and unconditionally and jointly and severally guaranteed the 5.5% senior notes and the 7.5% senior notes. SMLP has no independent assets or operations. Summit Holdings has no assets or operations other than its ownership of its wholly owned subsidiaries and activities associated with its borrowings under the revolving credit facility, the 5.5% senior notes and the 7.5% senior notes. Finance Corp. has no independent assets or operations and was formed for the sole purpose of being a co-issuer of certain of Summit Holdings' indebtedness, including the 5.5% senior notes and the 7.5% senior notes. There are no significant restrictions on the ability of SMLP or Summit Holdings to obtain funds from its subsidiaries by dividend or loan.

5.5% Senior Notes. We will pay interest on the 5.5% senior notes semi-annually in cash in arrears on February 15 and August 15 of each year, commencing February 15, 2015. The 5.5% senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 5.5% senior notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the

Table of Contents

collateral securing such indebtedness. We used the proceeds from the issuance of the 5.5% senior notes to repay a portion of the balance outstanding under our revolving credit facility.

At any time prior to August 15, 2017, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 5.5% senior notes at a redemption price of 105.500% of the principal amount of the 5.5% senior notes, plus accrued and unpaid interest, if any, to the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after August 15, 2017, the Co-Issuers may redeem all or part of the 5.5% senior notes at a redemption price of 104.125% (with the redemption premium declining ratably each year to 100.000% on and after August 15, 2020), plus accrued and unpaid interest, if any. Debt issuance costs of $5.1 million, recognized in other noncurrent assets, are being amortized over the life of the senior notes.

The 5.5% senior notes' indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 5.5% senior notes' indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 5.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 5.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 5.5% senior notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 5.5% senior notes may declare all the 5.5% senior notes to be due and payable immediately.

As of December 31, 2014, we were in compliance with the covenants for the 5.5% senior notes. There were no defaults or events of default for the 5.5% senior notes during the period from issuance through December 31, 2014.

7.5% Senior Notes. The 7.5% senior notes were sold within the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and outside the United States only to non-U.S. persons in reliance on Regulation S under the Securities Act.

We pay interest on the 7.5% senior notes semi-annually in cash in arrears on January 1 and July 1 of each year. The 7.5% senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 7.5% senior notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. We used the proceeds from the issuance of the 7.5% senior notes to repay a portion of the balance outstanding under our revolving credit facility.

Effective as of April 7, 2014, all of the holders of our 7.5% senior notes exchanged their unregistered senior notes and the guarantees of those notes for registered notes and guarantees. The terms of the registered senior notes are substantially identical to the terms of the unregistered senior notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the unregistered senior notes do not apply to the registered senior notes.

At any time prior to July 1, 2016, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 7.5% senior notes at a redemption price of 107.500% of the principal amount of the 7.5% senior notes, plus accrued and unpaid interest, if any, to the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after July 1, 2016, the Co-Issuers may redeem all or part of the 7.5% senior notes at a redemption price of 105.625% (with the redemption premium declining ratably each year to 100.000% on and after July 1, 2019), plus accrued and unpaid interest, if any. Debt issuance costs of $7.4 million, recognized in other noncurrent assets, are being amortized over the life of the senior notes.

The 7.5% senior notes indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 7.5% senior notes indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 7.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 7.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the 7.5% senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 7.5% senior notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 7.5% senior notes may declare all the 7.5% senior notes to be due and payable immediately.

As of December 31, 2014, we were in compliance with the covenants for the 7.5% senior notes. There were no defaults or events of default during the year ended December 31, 2014.

8. PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS

Partners' Capital

SMLP was formed in May 2012. Prior to the closing of its IPO on October 3, 2012, SMLP had no outstanding common or subordinated units or operations.

Table of Contents

A rollforward of the number of common limited partner, subordinated limited partner and general partner units follows.

	Common	Subordinated	General partner	Total
Units, January 1, 2012	—	—	—	—
Units issued to the public in connection with the IPO	14,380,000	—	—	14,380,000
Units issued to Summit Investments in connection with the IPO	10,029,850	24,409,850	996,320	35,436,020
Units issued under SMLP LTIP	2,577	—	—	2,577
Units, December 31, 2012	24,412,427	24,409,850	996,320	49,818,597
Units issued to a subsidiary of Summit Investments in connection with the Bison Drop Down (1)	1,553,849	—	31,711	1,585,560
Units issued to a subsidiary of Summit Investments in connection with the Mountaineer Acquisition (1)	3,107,698	—	63,422	3,171,120
Units issued under SMLP LTIP	5,892	—	—	5,892
Units, December 31, 2013	29,079,866	24,409,850	1,091,453	54,581,169
Units issued in connection with the March Equity 2014 Offering (1)	5,300,000	—	108,337	5,408,337