UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 8-K

CURRENT REPORT

Pursuant to Section 13 OR 15(d)
of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): September 11, 2015

Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	**001-35666**	**45-5200503**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1790 Hughes Landing Blvd
Suite 500
The Woodlands, TX 77380
(Address of principal executive offices) (Zip Code)

Registrants' telephone number, including area code: **(832) 413-4770**

Not applicable.
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

Summit Midstream Partners, LP ("SMLP" or the “Partnership”) is filing this Current Report on Form 8-K to update certain items in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Annual Report"). On May 18, 2015, SMLP acquired all of the membership interests of Polar Midstream, LLC (“Polar”) and Epping Transmission Company, LLC (collectively with Polar Midstream, "Polar and Divide") from Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned direct subsidiary of Summit Midstream Partners, LLC ("Summit Investments"), and thereby acquired certain crude oil and produced water gathering systems and under-development transmission pipelines located in the Williston Basin in North Dakota (the "Polar and Divide Drop Down"). Summit Investments, as the ultimate owner of SMLP's general partner, controls SMLP and has the right to appoint the entire board of directors of its general partner. As such, the Polar and Divide Drop Down was deemed a transaction among entities under common control and a change in reporting entity. Transfers of net assets or exchanges of membership interests between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to a pooling of interests. As a result, the following items of the 2014 Annual Report are being retrospectively adjusted to reflect the Polar and Divide Drop Down and the Partnership's 100% interest in the financial results of Polar and Divide for all periods during which common control existed:

- Item 1. Business;
- Item 1A. Risk Factors;
- Item 2. Properties;
- Item 6. Selected Financial Data;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations;
- Item 8. Financial Statements and Supplementary Data;
- Exhibit 12.1 Ratio of Earnings to Fixed Charges; and
- Exhibit 21.1 List of Subsidiaries.

These items replace the same items filed in the Partnership’s 2014 Annual Report as filed with the Securities and Exchange Commission (the "SEC") on March 2, 2015.

The information in this Current Report on Form 8-K should be read in conjunction with the other information included (but not replaced as described above) in the 2014 Annual Report. More current information is contained in the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015 and the Partnership's other filings with the SEC.

Forward-Looking Statements. The following forward-looking statements replace the same items included on pages ii and iii of the Partnership’s 2014 Annual Report as filed with the SEC on March 2, 2015.

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 be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “would,” and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us 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” in this report.

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

- fluctuations in natural gas, 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 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, crude oil and produced water;
- 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;
- 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 report 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.

Glossary of Terms. The following glossary of terms replaces the same items included on pages iv and v of the Partnership's 2014 Annual Report as filed with the SEC on March 2, 2015.

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 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

Bbl: one barrel; used for crude oil and produced water and equivalent to 42 U.S. gallons

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 or crude oil 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

hub: geographic location of a storage facility and multiple pipeline interconnections

LACT unit: lease automatic custody transfer unit; a system for ownership transfer of hydrocarbons from the production site to trucks, pipelines or storage tanks

Mcf: one thousand cubic feet

Mbbl: one thousand barrels

Mbbl/d: one thousand barrels per day

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 natural gas, crude oil or produced water 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

produced water: water from underground formations that is brought to the surface during crude oil production

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

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, crude oil or produced water transported or passing through a pipeline, plant or other facility during a particular period; also referred to as volume throughput

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. The following industry overview replaces the same information included on pages v and vi of the Partnership's 2014 Annual Report as filed with the SEC on March 2, 2015.

General

The midstream sector of the energy industry provides the link between exploration and production and the delivery of crude oil, natural gas and their components to end-use markets. The midstream sector consists generally of gathering, processing, storage, and transportation activities. We provide natural gas gathering, treating and processing services as well as crude oil and produced water gathering services.

Natural Gas Midstream Services

Companies within the natural gas midstream 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 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 and processing. Gathering systems are typically designed 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.

Crude Oil Midstream Services

Pipelines typically provide the most cost-effective option for shipping crude oil. Crude oil gathering systems typically comprise a network of small-diameter pipelines connected directly to the well head that transport crude oil to central receipt points or interconnecting pipelines through larger diameter trunk lines. Common carrier pipelines frequently transport crude oil from central delivery points to logistics hubs or refineries under tariffs regulated by the Federal Energy Regulatory Commission, also known as FERC, or state authorities. Logistic hubs provide storage and connections to other pipeline systems and modes of transportation, such as railroads and trucks. Pipelines not engaged in the interstate transportation of crude may also be proprietary or leased entirely to a single customer.

Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. Trucking is generally limited to low volume, short haul movements because trucking costs escalate sharply with distance, making trucking the most expensive mode of crude oil transportation. Railroads provide additional transportation capabilities for shipping crude oil between gathering storage systems, pipelines, terminals and storage centers and end-users.

Produced Water

Produced water is a by-product or waste stream associated with crude oil production. The cost of managing produced water is a key consideration for crude oil producers. Pipelines and trucking are used to gather produced water for transport to disposal facilities. Similar to crude oil gathering, trucking is generally limited to low volume, short haul movements.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit number		Description
12.1		Ratio of Earnings to Fixed Charges
21.1		List of Subsidiaries
23.1		Consent of Deloitte & Touche LLP
99.1		Updated 2014 Annual Report on Form 10-K - Item 1. Business.
99.2		Updated 2014 Annual Report on Form 10-K - Item 1A. Risk Factors.
99.3		Updated 2014 Annual Report on Form 10-K - Item 2. Properties.
99.4		Updated 2014 Annual Report on Form 10-K - Item 6. Selected Financial Data.
99.5		Updated 2014 Annual Report on Form 10-K - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.6		Updated 2014 Annual Report on Form 10-K - Item 8. Financial Statements and Supplementary Data.
101.INS	*	XBRL Instance Document (1)
101.SCH	*	XBRL Taxonomy Extension Schema
101.CAL	*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	*	XBRL Taxonomy Extension Definition Linkbase
101.LAB	*	XBRL Taxonomy Extension Label Linkbase
101.PRE	*	XBRL Taxonomy Extension Presentation Linkbase

* Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited and unreviewed.

(1) Includes the following materials for the year ended December 31, 2014, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Partners' Capital and Membership Interests, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Summit Midstream Partners, LP
(Registrant)

By: Summit Midstream GP, LLC (its general partner)

September 11, 2015

/s/ Matthew S. Harrison
Matthew S. Harrison, Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

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101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SUMMIT MIDSTREAM PARTNERS, LP
RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratio of earnings to fixed charges for the periods indicated on a consolidated historical basis. For purposes of computing the ratio of earnings to fixed charges, "earnings" are defined as income before taxes plus fixed charges less capitalized interest. "Fixed charges" consist of interest expensed and capitalized, amortization of deferred loan costs and an estimate of interest within rent expense.

	Year ended December 31,				
	2014 (1)	2013	2012	2011	2010
	(Dollars in thousands)				
Earnings:					
(Loss) income before income taxes	$ (14,103)	$ 53,566	$ 43,679	$ 38,646	$ 8,296
Add (deduct):					
Fixed charges	44,532	25,926	15,794	6,579	70
Capitalized interest	(3,778)	(6,255)	(2,784)	(3,362)	—
Total earnings	$ 26,651	$ 73,237	$ 56,689	$ 41,863	$ 8,366
Fixed Charges:					
Interest expense	$ 40,159	$ 19,173	$ 12,766	$ 3,054	$ —
Capitalized interest	3,778	6,255	2,784	3,362	—
Estimate of interest within rent expense	595	498	244	163	70
Total fixed charges	$ 44,532	$ 25,926	$ 15,794	$ 6,579	$ 70
Ratio of earnings to fixed charges	0.60	2.82	3.59	6.36	119.51

(1) The ratio of earnings to fixed charges was less than 1:1 for the year ended December 31, 2014. In order to achieve a ratio of earnings to fixed charges of 1:1, we would have had to generate an additional $17.9 million of earnings for the year ended December 31, 2014.

SUMMIT MIDSTREAM PARTNERS, LP
LIST OF SUBSIDIARIES

Name	State or other jurisdiction of incorporation or organization
Summit Midstream Holdings, LLC	Delaware
Grand River Gathering, LLC	Delaware
DFW Midstream Services LLC	Delaware
Bison Midstream, LLC	Delaware
Summit Midstream Finance Corp.	Delaware
Red Rock Gathering Company, LLC	Delaware
Polar Midstream, LLC	Delaware
Epping Transmission Company, LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-197311 and 333-191493 on Form S-3 and Nos. 333-184214 and 333-189684 on Form S-8 of our report dated March 2, 2015 (September 11, 2015 as to the effect of the 2015 Polar and Divide Drop Down as described in Notes 1 and 15), relating to the consolidated financial statements of Summit Midstream Partners, LP and subsidiaries (the "Partnership"); (which report expresses an unqualified opinion and includes explanatory paragraphs regarding the Partnership's change in presentation of its reportable segments, the retrospective adjustment for the acquisitions of Polar Midstream, LLC, Epping Transmission Company, LLC, Red Rock Gathering Company, LLC and Bison Midstream, LLC which were accounted for as a combination of entities under common control, and the acquisition of the Mountaineer Midstream gathering system on June 21, 2013), appearing in this Current Report on Form 8-K dated September 11, 2015 of Summit Midstream Partners, LP.

/s/ Deloitte & Touche LLP

Dallas, Texas
September 11, 2015

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 as well as crude oil and produced water gathering services pursuant to primarily long-term and fee-based 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 Polar and Divide 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");
- Whiting Petroleum Corp. ("Whiting") and SM Energy Company ("SM Energy"), which are the anchors for the Polar and Divide system ("Polar and Divide");

- Chesapeake Energy Corporation ("Chesapeake"), which is the anchor for the DFW Midstream system ("DFW Midstream"); and
- 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 that we gather, treat and process across our systems. As of December 31, 2014, our gathering systems had more than 2,600 miles of pipeline. During 2014, aggregate natural gas volume throughput averaged 1,418 MMcf/d and crude oil and produced water volume throughput averaged 33.6 Mbbl/d.

We generate a substantial majority of our revenue under long-term, primarily fee-based 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, substantially all of our revenue, net of pass-through items, was generated 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 1.6 million acres in the aggregate.

Certain of our 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 required volume throughput 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 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 4.0 trillion cubic feet equivalent ("Tcfe," determined using a ratio of six Mcf of gas to one barrel ("Bbl") of oil). Our MVCs have a weighted-average remaining life of 9.5 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1.3 Bcfe/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 gathering, treating and processing operations in the midstream sector through our five gathering systems, each of which represents one of our five 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 gathering systems and related property, plant and equipment.

Our financial results are primarily driven by the volumes 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.

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 approximately $1.9 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 to new geographic areas.*** Our gathering operations in the Marcellus, Bakken, Three Forks and Barnett shale plays and the Piceance Basin currently represent our core business. We 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 gathering and processing agreements. We believe that long-term, fee-based gathering and processing agreements enhance the stability of our cash flows by limiting our direct commodity price exposure.
- ***Capital structure and financial flexibility.*** At December 31, 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 five gathering systems:

- Mountaineer Midstream in northern West Virginia;
- Bison Midstream in northwestern North Dakota;
- Polar and Divide 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 volumes is primarily based on reputation, commercial terms, service levels, access to end-use markets, 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 gathering, treating and processing services pursuant to primarily long-term and fee-based gathering and processing agreements with some of the largest and most active producers in North America. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

The significant features of our gathering and processing agreements and the gathering systems to which they relate are discussed in more detail below. For additional 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, any production from wells drilled by our customers within that AMI will 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 gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. The original terms of our MVCs range from two to 15 years and had a weighted-average remaining life of 9.5 years as of December 31, 2014. In addition, certain of our customers have an aggregate MVC, which is a total amount of volume throughput that the customer has agreed to ship and/or process on our systems (or an equivalent monetary amount) over the MVC term. In these cases, once a customer achieves its aggregate MVC, any remaining future MVCs will terminate and the customer will then simply pay the applicable gathering or processing rate multiplied by the actual throughput volumes shipped or processed.

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.

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

(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 associated natural gas midstream services for the Williston Basin – Gas 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

(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.

Polar and Divide

In May 2015, we acquired certain crude oil and produced water gathering systems and transmission pipelines (under development) in the Williston Basin in northwestern North Dakota from a subsidiary of Summit Investments.

We refer to these assets, which commenced operations in May 2013, as the Polar and Divide system. The Polar and Divide system owns, operates, and is currently developing crude oil and produced water gathering systems and transmission pipelines in the Bakken Shale Play in North Dakota. Our gathering agreements for the Polar and Divide system are long-term, fee-based contracts. Several of these gathering agreements include rate redetermination mechanisms which effectively serve to protect future cash flows by resetting the gathering rate upward in the future in the event that the customer does not attain certain minimum production thresholds. The Polar and Divide system currently provides our crude oil and produced water midstream services for the Williston Basin – Liquids reportable segment.

The Polar and Divide system, which is located in Williams and Divide counties, consists of 274 miles of crude oil and produced water pipeline. Crude oil that is gathered by the Polar and Divide system is currently delivered to the COLT Hub in Epping, North Dakota and produced water is delivered to third-party disposal facilities located throughout the Williston Basin. From a development perspective, the Polar and Divide system has two additional growth projects underway:

- the Stampede Lateral, a 46-mile, 10-inch diameter crude oil transmission pipeline development project with throughput capacity of 50 Mbbl/d that connects to Global Partners LP's Basin Columbus rail hub for delivery to east coast markets and
- the Little Muddy Interconnect, a 15-mile, 10-inch diameter pipeline with crude oil tankage and an interconnect into Enbridge's North Dakota Pipeline System that is expected to be commissioned in the fourth quarter of 2015.

The following table provides information regarding our Polar and Divide system as of December 31, 2014.

Gathering system	Approximate length (Miles)	Throughput capacity (Mbbl/d)	Approximate AMIs (Acres)
Polar and Divide (1)	274	80	192,600

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

The Polar and Divide system is underpinned by two long-term, fee-based gathering agreements with our anchor customers Whiting and SM Energy. In addition to Whiting and SM Energy, the Polar and Divide system is also supported by other long-term, fee-based gathering agreements and has executed commitments to expand the system to additional customer pad sites. We will continue to develop the Polar and Divide system to extend our gathering reach, increase capacity, increase our receipt points and maximize throughput.

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 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

(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 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 October 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 system, 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

(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, primarily 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.

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 Crude Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and NGLs are not currently regulated and are transacted at market prices. In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. FERC, which has the authority under the 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 and Crude Oil. We believe that our natural 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") and movement of crude oil on our crude oil pipelines are not currently subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"), although we are subject to FERC's anti-market manipulation regulations. The distinction between federally unregulated natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and changes in the policies and interpretations of laws and regulations. In addition, the status of any individual 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 or Utah 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, crude oil and produced water production, gathering and transportation, including the construction of new gathering facilities and expansion of existing gathering facilities may also be subject to local regulation, such as approval and permit requirements.

Anti-Market Manipulation Rules. We are subject to the anti-market manipulation provisions in the 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 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, which establishes federal safety standards for the design, construction, operation and maintenance of natural gas and crude oil pipeline facilities. In the Pipeline Safety Act of 1992, Congress expanded the 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.

Environmental Matters

General. Our operation of pipelines and other assets for the gathering of natural gas, crude oil and produced water and compression 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.

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

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

- the level and timing of capital expenditures we make;
- the level of our operating, maintenance and general and administrative expenses, including reimbursements of expenses incurred on our behalf by our general partner;
- the cost of acquisitions, if any;
- our 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.

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

Our operations are focused on gathering, treating and processing services in 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 limited industry and geographic diversity, adverse developments in the natural gas and crude oil industries or in our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows.

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

The current level of 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 further 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. In addition, 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.

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 that we gather and process could materially adversely affect our business and operating results.

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

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling and production decisions, which are affected by, among other things:

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

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, including NGLs.

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

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

Many of our costs are fixed and do not vary with our throughput. These costs may not decline ratably or at all should we experience a reduction in throughput, which could 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 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 certain of our 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.

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

Our 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 certain of these minimum volume commitments, our customers agree to ship a minimum volume on our gathering systems or send 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 gathering and processing agreements also include an aggregate minimum volume commitment, which is a total amount 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 gathering agreements contain provisions that allow the customer to use the excess volumes or the shortfall payment to credit against future excess volumes or future shortfall payments, which could have a material adverse effect on our results of operations, financial condition and cash flows and our ability to make cash distributions to our unitholders.

We do not intend to obtain independent evaluations of the reserves connected to our gathering systems on a regular or ongoing basis; therefore, in the future, customer volumes on our systems could be less than we anticipate.

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

Accordingly, we may not have accurate estimates of total reserves dedicated to 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 volumes, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

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

In addition, our customers may develop their own gathering systems outside of our areas of mutual interest. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current 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.

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

- the level of existing and new competition to provide gathering and/or processing services in our areas of operation;
- the macroeconomic factors affecting gathering, treating and processing economics for our current and potential customers;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our areas of operation are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

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

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

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

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

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 gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other 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, crude oil and produced water that we gather and/or 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 energy industry could reduce employee productivity and increase costs, which could have a material adverse effect on our business and results of operations.

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

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 crude oil and natural 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 supplied to our gathering systems. Further, delays and shutdowns caused by severe weather during the winter months may have a material negative impact on the continuous operations of our gathering, treating and processing systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet 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 provide gathering, treating or processing services, could adversely affect our operations and cash flows available for distribution to our unitholders.

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

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

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

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

These risks may also result in curtailment or suspension of our operations. A natural disaster or any event such as those described above affecting the areas in which we and our customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on 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.

Our insurance coverage is provided by policies that cover all of our assets and those of Summit Investments and its non-SMLP subsidiaries. Therefore, it is possible that an incident, or incidents, at those subsidiaries could exhaust claim capacity and leave SMLP and its subsidiaries exposed to risk of loss should they experience a loss during the same policy cycle. In addition, although we have a range of insurance programs providing varying levels of protection for public liability, damage to property, loss of income and certain environmental hazards, we may not be insured against all causes of loss, claims or damage that may occur. If a significant 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 and/or claims by Summit Investments or its non-SMLP subsidiaries may increase rates on all of the insured-asset group, including those owned by SMLP and its subsidiaries. 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 relies, in part, on the continued divestiture of midstream assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

If we are unable to make accretive acquisitions from 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 successfully integrate the assets or businesses we acquire;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- mistaken assumptions about the overall costs of debt or equity capital;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines;
- customer or key employee losses at the acquired businesses;
- production declines higher than anticipated; and
- facilities being properly constructed.

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

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, our revenue may not increase immediately upon the expenditure of funds for a particular project and they may not be completed on schedule, at the budgeted cost, or at all.

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

In addition, the construction of additions or modifications to our existing gathering, treating and processing assets and the construction of new midstream assets may require us to obtain 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 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 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 gathering and processing agreements also require us to spend significant amounts of capital, over a short period of time, to construct and develop additional midstream assets to support our customers' development projects. Depending on our customers' future development plans, it is possible that the capital we would be required to spend to construct and develop such assets could exceed our ability to finance those expenditures using our cash reserves or available capacity under our amended and restated revolving credit facility.

We plan to use cash from operations, incur borrowings, and/or sell additional common units or other securities to fund our future expansion capital expenditures. Using cash from operations to fund expansion capital expenditures will directly reduce our cash available for distribution to unitholders. Our ability to obtain financing or to access the capital markets for future debt or equity offerings may be limited by 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 production volumes from our customers with whom we have agreed to construct and develop midstream assets in the future. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional units representing limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

We do not have a contractual 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 among other things:

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

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

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 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, natural gas and NGL prices, and our exposure may increase in the future.

We generate a substantial majority of our revenues pursuant to primarily long-term and fee-based gathering and processing agreements under which we are paid based on the volumes that we gather and/or process rather than the value of the underlying commodity or related byproduct. 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 gathering and processing agreements. For example, we have percent-of-proceeds and keep-whole contracts with certain natural gas producer customers and we may, in the future, enter into additional percent-of-proceeds and keep-whole contracts with these customers, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of the underlying commodities. 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, (ii) the sale of condensate volumes that we retain at Grand River Gathering, and (iii) the sale of processed natural gas and NGLs pursuant to our percent-of-proceeds and keep-whole contracts with certain of our customers on the Bison Midstream and Grand River Gathering systems. 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 and other NGLs.

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

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

Various aspects of our operations are subject to regulation by the various federal, state and local departments and agencies that have jurisdiction over participants in the energy industry. The regulation of our activities and the natural gas and crude oil industries frequently change as they are reviewed by legislators and regulators. In 2014, the North Dakota Industrial Commission began to oversee the integrity and location of underground gathering pipelines that are not monitored by other state or federal agencies and is considering additional rule changes that could result in additional construction and monitoring requirements for all pipelines, including, but not limited to, those that transport produced water. 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 drilling activity could directly curtail such activity or increase the cost of drilling, resulting in reduced levels of drilling activity and therefore reduced demand for our services. Regulatory agencies establish and, from time to time, change priorities, which may result in additional burdens on us, such as additional reporting requirements and more frequent audits of operations. Our operations and the markets in which we participate are affected by these laws, regulations and interpretations and may be affected by changes to them or their implementation, which may cause us to realize materially lower revenues or incur materially increased operation and maintenance costs or both.

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

Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily regulated by state agencies. However, Congress has in the past and may in the future consider legislation to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing, and are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. The Environmental Protection Agency ("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. If new or more stringent federal, state or local legal restrictions relating to such drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil, which could adversely affect our results of operations and financial condition.

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

We believe that our natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of The Federal Energy Regulatory Commission ("FERC"), the Natural Gas Act ("NGA") and the Natural Gas Policy Act of 1978 (the "NGPA") and movements of crude oil on our crude oil pipelines are not currently subject to FERC jurisdiction under the Interstate Commerce Act (“ICA”). 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 Commodity Futures Trading Commission (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 (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 natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and is determined by FERC on a case-by-case basis. FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by FERC, Congress or the courts. If our natural gas gathering operations or crude oil operations become subject to FERC jurisdiction over interstate service under the NGA, the NGPA or the ICA, the result may materially adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, the NGPA or the ICA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

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

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

Our gathering, treating and processing operations are subject to stringent and complex federal, state and local environmental laws and regulations, including laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection, including, for example, the Clean Air Act, the

Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Water Act; the Oil Pollution Act; the Resource Conservation and Recovery Act; the Endangered Species Act; and the Toxic Substances Control Act.

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

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

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

The DOT, through its Pipeline and Hazardous Materials Safety Administration (the "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 services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of greenhouse gases (“GHGs”), such as carbon dioxide and methane that may be contributing to global warming. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation.

Independent of Congress, the EPA has begun to adopt regulations under its existing 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 Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for certain large stationary sources of GHG emissions. In addition, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG-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 GHG emissions could require us to incur increased operating costs and could materially adversely affect demand for our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of GHG could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions and administer and manage a GHG emissions program. While we may be able to include some or all of such increased costs in the rates we charge, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The 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 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.

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 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 energy industry experience and competition for these persons in the midstream energy industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

Risks Inherent in an Investment in Us

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

Summit Investments controls our general partner and has authority to appoint all of the officers and directors of our general partner, some of whom 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, which is expected to end in February 2016 assuming we continue to have earned and paid at least $1.60 on each outstanding limited partner unit and the corresponding distribution on our general partner's 2.0% interest for each of the three consecutive, non-overlapping four-quarter periods ending on December 31, 2015.
- 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 IDRs.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's IDRs without the approval of the conflicts committee 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.

Our Sponsor has significantly greater resources than us and has experience making investments in midstream energy businesses. Although it controls Summit Investments, our Sponsor 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, Energy Capital Partners and Summit Investments may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities.

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

The amount of cash we have available for distribution to holders of our 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 report net losses for GAAP purposes and may not make cash distributions during periods when we report net income for GAAP purposes.

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

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, limited liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

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

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by our 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, including those held by Summit Investments and its subsidiaries; and
- other factors described in these Risk Factors.

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

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

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

Our partnership agreement replaces our general partner's fiduciary duties to unitholders with contractual standards governing its duties.

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

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee 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 IDRs or any units it owns to a third party; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

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 acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our partnership agreement, our amended and restated revolving credit facility or senior notes indentures 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. The subordination period is expected to end in February 2016 assuming we continue to have earned and paid at least $1.60 on each outstanding limited partner unit and the corresponding distribution on our general partner's 2.0% interest for each of the three consecutive non-overlapping four-quarter periods ending on December 31, 2015. 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 expenses incurred on our behalf will reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our general partner.

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

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

The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of December 31, 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, representing a voting block sufficient to prevent the other limited partners from removing our general partner. 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.

Our general partner's IDRs may be transferred to a third party without unitholder consent.

Our general partner may transfer the IDRs it owns to a third party at any time without the consent of our unitholders. If our general partner transfers the IDRs to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our business and increase quarterly distributions to unitholders over time as it would if it had retained ownership of the incentive distribution rights. For example, a transfer of the IDRs 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 IDRs is based on a percentage of the total cash available for distribution, the distributions to holders of IDRs will increase even if the per-unit distribution on common units remains the same;
- 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. (The subordination period is expected to end in February 2016 assuming we continue to have earned and paid at least $1.60 on each outstanding limited partner unit and the corresponding distribution on our general partner's 2.0% interest for each of the three consecutive non-overlapping four-quarter periods ending on December 31, 2015.) We have agreed to provide this subsidiary 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 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 or the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our general partner.

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 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 U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including ours.

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

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.

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 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 2. Properties.

We currently have five 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 Polar and Divide system located in Williams and Divide counties, North Dakota, (iv) the DFW Midstream system located primarily in Tarrant County, Texas and (v) 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.

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 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) Polar and Divide since February 16, 2013, (ii) Bison Midstream since February 16, 2013, (iii) Mountaineer Midstream since June 22, 2013, (iv) Red Rock Gathering since October 23, 2012 and (v) Grand River Gathering since October 27, 2011. SMLP recognized its acquisitions of Polar and Divide (the "Polar and Divide Drop Down"), 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 Polar and Divide and 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 Polar and Divide Drop Down, 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.

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	$ 2,293,721	$ 2,191,143	$ 1,280,939	$ 1,030,264	$ 340,095
Total long-term debt	808,000	586,000	199,230	349,893	—
Partners' capital	1,351,721	1,493,087	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

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	$ 353,135	$ 296,813	$ 174,423	$ 103,552	$ 31,676
Total costs and expenses	328,268	224,079	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	(14,734)	52,837	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	$ 114,345	$ 144,340	$ 93,302	$ 53,363	$ 12,353
Adjusted EBITDA	204,907	165,324	105,946	56,803	12,353
Capital expenditures	220,820	182,978	77,296	78,248	153,719
Acquisition capital expenditures (1)	315,872	458,914	—	589,462	—
Distributable cash flow	150,318	128,457	90,947	50,980	11,726
Distributions declared per unit (2)	2.120	1.795	0.410	n/a	n/a

n/a - Not applicable
(1) Reflects cash paid (including working capital and capital expenditure adjustments) 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.
(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 in this report. 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. Our gathering systems and the unconventional resource basins in which they operate are as follows:

- Mountaineer Midstream, a natural gas gathering system located in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream, an associated natural gas gathering system located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Polar and Divide, a crude oil and produced water gathering system and transmission pipelines (under development) located in the Williston Basin;
- DFW Midstream, a natural gas gathering system located in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Grand River Gathering, a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

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

We provide natural gas gathering, treating and processing services as well as crude oil and produced water gathering services pursuant to primarily long-term and fee-based gathering and processing agreements with our customers and counterparties. We contract with producers to gather natural gas from pad sites, wells and central receipt points connected to our systems. We then compress, dehydrate, treat and/or process these volumes for delivery to downstream pipelines for ultimate delivery to third-party processing plants and/or end users. We also contract with producers to gather crude oil and produced water from wells connected to our systems for delivery to third-party rail terminals in the case of crude oil and to third-party disposal facilities in the case of produced water.

Our results are driven primarily by the volumes that we gather, treat and/or process. 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 a substantial majority of these agreements, we are paid a fixed fee based on the volumes 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 (i) crude oil and produced water gathering, (ii) our marketing of natural gas and natural gas liquids, (iii) the sale of physical natural gas purchased from our customers under percentage-of-proceeds and keep-whole arrangements, and (iv) from the sale of condensate retained from our gathering services at Grand River Gathering. We can be exposed to commodity price risk from engaging in any of these additional activities with the exception of produced water gathering.

We also 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 and crude oil (and associated volumes of produced water) 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 gathering agreements are underpinned by AMIs and MVCs. Our AMIs cover over 1.6 million acres in the aggregate and provide that any production from wells drilled by our customers within the AMI will be shipped on our gathering systems. Our MVCs, which totaled 4.0 trillion cubic feet equivalent ("Tcfe," determined using a ratio of six Mcf of gas to one barrel ("Bbl") of oil) at December 31, 2014 and average approximately 1.3 Bcfe/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 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 9.5 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" 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, since 2013, we have acquired Bison Midstream, Red Rock Gathering and Polar and Divide from a subsidiary of Summit Investments as well as Mountaineer Midstream from an affiliate of MarkWest.

Summit Investments 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 made and expects to continue making significant investments 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 over the next several years.

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, 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 the section entitled "Risk Factors" in this report.

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.

In addition, the Bison Midstream and Polar and Divide systems are 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 and Polar and Divide systems, 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 energy industry through five reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin – Gas, which is served by Bison Midstream;
- the Williston Basin – Liquids, which is served by Polar and Divide;
- 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 (i) natural gas that we gather, treat and/or process and (ii) crude oil and produced water that we gather depends on the level of production from natural gas or crude oil wells connected to our gathering systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity. Furthermore, because the production rate of natural gas and crude oil wells decline over time, production can only be maintained or increased by new drilling or other activity.

As a result, we must continually obtain new supplies of production to maintain or increase the throughput volume on our systems. Our ability to maintain or increase throughput volumes from existing customers and obtain new customers or counterparties 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/or process production that has been released from commitments with our competitors.

Following the Polar and Divide Drop Down, we will continue to report volumes for natural gas gathering and will now also report volumes for crude oil and produced water gathering. Crude oil and produced water gathering are aggregated and reported as "liquids" gathering and measured in thousands of barrels per day ("Mbbl/d"). Gathering rates are reported in barrels.

Revenues

Our revenues are primarily attributable to the volumes that we gather, treat and/or process and the rates we charge for those services. A substantial majority of our gathering and processing agreements are fee-based, which limits our direct commodity price exposure. We also have percent-of-proceeds 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 gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. These MVCs support our revenues and serve to mitigate the financial impact associated with declining volumes.

In connection with the Polar and Divide Drop Down, we evaluated our classification of revenues and concluded that creating an “other revenues” category would provide reporting that was more reflective of our results of operations and how we manage our business. As such, certain revenue transactions that previously represented the “and other” portions of (i) gathering services and (ii) natural gas, NGLs and condensate sales have been reclassified to other revenues. Other revenues largely comprises electricity pass-throughs for customers of Bison Midstream and Grand River Gathering and connection fees on the Polar and Divide system. Other revenues also includes the amortization expense associated with our favorable and unfavorable gas gathering contracts. These reclassifications had no impact on total revenues, net income or total partners' capital.

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.

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

Natural gas, NGLs and condensate sales. Revenue earned from (i) the sale of physical natural gas and natural gas liquids purchased 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.

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

Cost of natural gas and NGLs. The cost of natural gas and NGLs represents 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.

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 Polar and Divide since February 16, 2013. We accounted for the Polar and Divide Drop Down on an "as-if pooled" basis because the transaction was executed by entities under common control. The Polar and Divide system commenced operations in May 2013.
- 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.

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

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 related fees	$ 239,595	$ 197,174	$ 145,463	22 %	36%
Natural gas, NGLs and condensate sales	97,094	88,185	22,825	10 %	*
Other revenues	16,446	11,454	6,135	44 %	87%
Total revenues	353,135	296,813	174,423	19 %	70%
Costs and expenses:					
Cost of natural gas and NGLs	52,847	41,164	3,224	28 %	*
Operation and maintenance	88,927	77,114	53,882	15 %	43%
General and administrative	38,269	32,273	22,182	19 %	45%
Transaction costs	730	2,841	2,025	(74)%	40%
Depreciation and amortization	87,349	70,574	36,674	24 %	92%
Loss on asset sales, net	442	113	—	*	*
Goodwill impairment	54,199	—	—	*	—%
Long-lived asset impairment	5,505	—	—	*	—%
Total costs and expenses	328,268	224,079	117,987	46 %	90%
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	(14,103)	53,566	43,679	(126)%	23%
Income tax expense	(631)	(729)	(682)	(13)%	7%
Net (loss) income	$ (14,734)	$ 52,837	$ 42,997	(128)%	23%
Other Financial Data:					
EBITDA (1)	$ 114,345	$ 144,340	$ 93,302	(21)%	55%
Adjusted EBITDA (1)	204,907	165,324	105,946	24 %	56%
Capital expenditures (2)	220,820	182,978	77,296	21 %	137%
Acquisitions of gathering systems (3)	315,872	458,914	—	*	*
Distributable cash flow (1)(2)	150,318	128,457	90,947	17 %	41%
Operating Data:					
Miles of pipeline as of December 31	2,622	2,449	1,874	7 %	31%
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%
Average throughput (Mbbl/d)	33.6	10.9		*	
Average throughput rate per Bbl	$ 1.64	$ 0.95		73 %	

*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 (including working capital and capital expenditure adjustments) 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.

Volumes – Gas. 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.

Volumes – Liquids. Average daily throughput for crude oil and produced water increased to 33.6 Mbbl/d for the year ended December 31, 2014, compared with an average of 10.9 Mbbl/d in the prior-year period. The increase in crude oil and produced water volume throughput primarily reflects the continued development of the Polar and Divide system, new pad site connections and producers' ongoing drilling activity.

Revenues. For the year ended December 31, 2014, total revenues increased $56.3 million, or 19%, and primarily reflect:

- overall growth at Red Rock Gathering;
- overall growth at Polar and Divide;
- 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 $122.4 million, or 70%, and primarily reflect:

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

Costs and Expenses. For the year ended December 31, 2014, total costs and expenses increased $104.2 million, or 46%, primarily due to a goodwill impairment for Bison Midstream, an increase in depreciation and amortization across our gathering systems, an increase in cost of natural gas and NGLs for Bison Midstream and Red Rock Gathering and an increase in operation and maintenance expense as a result of the continued development of the Polar and Divide system.

For the year ended December 31, 2013, total costs and expenses increased $106.1 million, or 90%, primarily as a result of a full year of operations for Red Rock Gathering and the partial-year contributions from Bison Midstream, Mountaineer Midstream and Polar and Divide 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.

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 related 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	*

* 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 Related Fees. Gathering services and related 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 – Gas. The Bison Midstream gathering system provides our midstream services for the Williston Basin – Gas 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 – Gas 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.

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

	Williston Basin – Gas		
	Year ended December 31,		Percentage Change
	2014	2013	2014 v. 2013
	(Dollars in thousands, except fee-rate data)		
Revenues:			
Gathering services and related fees	$ 946	$ 536	76 %
Natural gas, NGLs and condensate sales	56,040	47,130	19 %
Other revenues	5,468	3,069	78 %
Total revenues	62,454	50,735	23 %
Costs and expenses:			
Cost of natural gas and NGLs	34,912	27,967	25 %
Operation and maintenance	14,360	7,269	98 %
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)%

* 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 Related Fees. Gathering services and related 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. The increase in natural gas, NGLs and condensate sales 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.

Other Revenues. The increase in other revenues for the year ended December 31, 2014 reflects an increase in certain electricity expenses, which, due to their pass-through nature, is offset in operation and maintenance expense and has no impact on segment adjusted EBITDA.

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 $2.2 million increase in electricity pass-through expense as discussed in other revenues above, 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.

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.

Williston Basin – Liquids. The Polar and Divide system provides our midstream services for the Williston Basin – Liquids reportable segment. Polar and Divide was acquired from a subsidiary of Summit Investments in May 2015. Our results include activity for Polar and Divide since February 16, 2013, the date on which common control began. Volume throughput for Polar and Divide averaged 33.6 Mbbl/d for the year ended December 31, 2014, compared with 12.5 Mbbl/d during our period of ownership in 2013. The increase in volume throughput in 2014 reflects new pad site connections and ongoing drilling activity in Polar and Divide's service area.

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

	Williston Basin – Liquids		
	Year ended December 31,		Percentage Change
	2014	2013	2014 v. 2013
	(Dollars in thousands, except fee-rate data)		
Revenues:			
Gathering services and related fees	$ 20,110	$ 3,791	*
Other revenues	2,339	102	*
Total revenues	22,449	3,893	*
Costs and expenses:			
Operation and maintenance	7,408	1,580	*
General and administrative	4,252	2,168	96%
Depreciation and amortization	4,359	612	*
Total costs and expenses	16,019	4,360	*
Add:			
Depreciation and amortization	4,359	612	
Unit-based compensation	340	340	
Segment adjusted EBITDA	$ 11,129	$ 485	*
Average throughput (Mbbl/d)(1)	33.6	10.9	*
Average throughput rate per Bbl	$ 1.64	$ 0.95	73%

* Not considered meaningful
(1) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 12.5 Mbbl/d.

Gathering Services and Related Fees. Gathering services and related fees increased during the year ended December 31, 2014 primarily a result of the impact of higher volume throughput on gathering services and related fees and higher gathering rates associated with contract amendments in 2014. The aggregate average throughput rate increased to $1.64 per Bbl in 2014 from $0.95 per Bbl in 2013, primarily as a result of contract amendments in 2014 which increased gathering rates in connection with our commitment to further expand the Polar and Divide system.

Other revenues. The increase in other revenues for the year ended December 31, 2014 was primarily a result of an increase in connection fees, which, due to their pass-through nature, is offset in operation and maintenance expense.

Operation and Maintenance. Operation and maintenance expense increased during the year ended December 31, 2014, largely as a result of the previous mentioned increase in connection fees, which, due to their pass-through nature, is offset in other revenues and an increase in salaries, benefits and incentive compensation primarily as a result of increased head count.

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.

Depreciation and Amortization. The increase in depreciation and amortization expense during the year ended December 31, 2014 was largely driven by assets being placed into service.

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 related fees	$ 79,976	$ 89,147	$ 78,472	(10)%	14 %
Natural gas, NGLs and condensate sales	13,448	17,190	15,173	(22)%	13 %
Other revenues	(423)	(1,013)	(192)	(58)%	*
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 %

* Not considered meaningful

Gathering Services and Related Fees. Gathering services and related 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. The decrease in natural gas, NGLs and condensate sales 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 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.

Other Revenues. Other revenues increased during the year ended December 31, 2014 largely as a result of the contribution of Lonestar reimbursement revenues.

For the year ended December 31, 2013, a substantial majority of other revenues was related to the amortization of favorable and unfavorable gas gathering contracts. In 2012, other revenues comprised the amortization of favorable and unfavorable gas gathering contracts.

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.

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 related fees	$ 115,869	$ 94,112	$ 66,991	23 %	40%
Natural gas, NGLs and condensate sales	27,606	23,865	7,652	16 %	*
Other revenues	9,062	9,296	7,318	(3)%	27%
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 Related Fees. Gathering services and related 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 related 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 related fees included a $28.5 million contribution as a result of the Red Rock Drop Down, compared with a $3.9 million contribution in 2012.

Natural Gas, NGLs and Condensate Sales. The increase in natural gas, NGLs and condensate sales 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 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 included a $19.3 million contribution as a result of the Red Rock Drop Down, compared with a $4.1 million contribution in 2012.

Other Revenues. The decrease in other revenues for the year ended December 31, 2014 was primarily a result of a $1.1 million decrease in field services revenue, which was partially offset by a $0.7 million increase in reimburseable electricity expense, which due to its pass-through nature, is offset in operation and maintenance expense.

Other revenues increased during the year ended December 31, 2013, largely as a result of the recognition of $1.1 million of field services revenue, a $0.6 million increase in NGL injection fees and a $0.5 million increase in reimburseable electricity expense, which due to its pass-through nature, is offset in operation and maintenance expense.

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.

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 results that are not specifically attributable to a reportable segment or that have not been allocated to our reportable segments, including certain general and administrative expense items, 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 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 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:

- 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.
- Depreciation and amortization includes the favorable and unfavorable gas gathering contract amortization expense reported in other revenues.
- 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.
- The goodwill impairment recognized in the year ended December 31, 2014 relates to the Bison Midstream system of our Williston Basin – Gas segment. See "Results of Operations—Williston Basin – Gas," "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.
- As a result of accounting for our drop down transactions similar to a pooling of interests, EBITDA, adjusted EBITDA, and distributable cash flow reflect the historical operations, financial position and cash flows of Polar Midstream, Epping and Red Rock Gathering for the periods beginning with the date that common control began and ending on the date that the respective drop down closed. See Notes 1 and 15 to the audited consolidated financial statements for additional information.
- 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.

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	$ (14,734)	$ 52,837	$ 42,997
Add:			
Interest expense	40,159	19,173	12,766
Income tax expense	631	729	682
Depreciation and amortization	88,293	71,606	36,866
Less:			
Interest income	4	5	9
EBITDA	$ 114,345	$ 144,340	$ 93,302
Add:			
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	5,036	3,846	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	$ 204,907	$ 165,324	$ 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	16,336	15,071	6,075
Distributable cash flow	$ 150,318	$ 128,457	$ 90,947

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	$ 154,997	$ 140,469	$ 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	(14,671)	(9,821)	(769)
Less:			
Unit-based compensation	5,036	3,846	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	$ 114,345	$ 144,340	$ 93,302
Add:			
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	5,036	3,846	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	$ 204,907	$ 165,324	$ 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	16,336	15,071	6,075
Distributable cash flow	$ 150,318	$ 128,457	$ 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.

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.

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.

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	$ 154,997	$ 140,469	$ 89,392
Net cash used in investing activities	(536,367)	(592,393)	(77,296)
Net cash provided by (used in) financing activities	387,517	460,947	(16,224)
Change in cash and cash equivalents	$ 6,147	$ 9,023	$ (4,128)

Operating activities. Cash flows from operating activities increased by $14.5 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 $51.1 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 Polar and Divide, 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 and build out of the Polar and Divide system. 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 and construction of the Polar and Divide system. 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.

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, net	197,806	—	263,125
Contribution from general partner	4,235	2,229	—
Cash advance from Summit Investments to contributed subsidiaries, net	81,421	72,745	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	10,483	11,964	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	$ 387,517	$ 460,947	$ (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;
- 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); and
- Cash advances to support the buildout of the Polar and Divide system.

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

- Cash advances to support the buildout of the Polar and Divide system.

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)	24,122	20,547	3,462	113	—
Total contractual obligations	$ 1,152,341	$ 67,561	$ 97,489	$ 292,791	$ 694,500

(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 $220.8 million, which included $16.3 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 construction of the Polar and Divide system, compression capacity expansion work on the Bison Midstream system and the construction of pipeline and additional compressor capacity for Mountaineer Midstream.

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 $1.4 billion and net intangible assets with a carrying value of approximately $477.7 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 Polar and Divide and Bison Midstream systems. In connection with this evaluation, we also evaluated the property, plant and equipment and intangible assets of these 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 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 four reporting units which have goodwill: (i) Polar and Divide, (ii) Grand River Gathering, (iii) Bison Midstream and (iv) Mountaineer Midstream.

We performed our annual goodwill impairment analysis as of September 30, 2014. We determined that the fair value of the Polar and Divide, 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 Polar and Divide, 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 Polar and Divide and Bison Midstream reporting units could have been impaired. In connection therewith, we noted that the Polar and Divide reporting unit had been impacted by the recent price declines, thereby increasing the likelihood that the associated goodwill could have been impaired. As such, we concluded that a triggering event occurred during the fourth quarter of 2014 requiring that we test Polar Midstream's goodwill. The results of our step one goodwill impairment testing indicated that the fair value of the Polar and Divide reporting unit exceeded its carrying value, including goodwill. Because its fair value exceeded its carrying value, including goodwill, there was no impairment associated with the fourth quarter triggering event.

We also 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 gathering agreements provide for a monthly or annual MVC from our customers. As of December 31, 2014, we had MVCs totaling 4.0 Tcf through 2026. Under these monthly, quarterly or annual MVCs, our customers agree to ship a minimum volume of throughput 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.

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 volume throughput, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable 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 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 – Gas	$ 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.

Item 8. Financial Statements and Supplementary Data.

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 the 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 on February 15, 2013 and Red Rock Gathering Company, LLC on March 18, 2014, 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 consolidated financial statements also give retrospective effect to the Partnership's acquisition of Polar Midstream, LLC and Epping Transmission Company, LLC, on May 18, 2015 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 (not presented herein) expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Dallas, Texas
March 2, 2015
(September 11, 2015 as to the effects of the 2015 Polar and Divide Drop Down as described in Notes 1 and 15)

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 26,504	$ 20,357
Accounts receivable	89,201	69,790
Other current assets	3,517	4,959
Total current assets	119,222	95,106
Property, plant and equipment, net	1,414,350	1,256,314
Intangible assets, net	477,734	505,844
Goodwill	265,062	319,261
Other noncurrent assets	17,353	14,618
Total assets	$ 2,293,721	$ 2,191,143
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$ 24,855	$ 38,507
Due to affiliate	2,711	653
Deferred revenue	2,377	1,555
Ad valorem taxes payable	9,118	8,375
Accrued interest	18,858	12,144
Other current liabilities	13,550	14,393
Total current liabilities	71,469	75,627
Long-term debt	808,000	586,000
Unfavorable gas gathering contract, net	5,577	6,374
Deferred revenue	55,239	29,683
Other noncurrent liabilities	1,715	372
Total liabilities	942,000	698,056
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	384,832	523,944
Total partners' capital	1,351,721	1,493,087
Total liabilities and partners' capital	$ 2,293,721	$ 2,191,143

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

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 related fees	$ 239,595	$ 197,174	$ 145,463
Natural gas, NGLs and condensate sales	97,094	88,185	22,825
Other revenues	16,446	11,454	6,135
Total revenues	353,135	296,813	174,423
Costs and expenses:			
Cost of natural gas and NGLs	52,847	41,164	3,224
Operation and maintenance	88,927	77,114	53,882
General and administrative	38,269	32,273	22,182
Transaction costs	730	2,841	2,025
Depreciation and amortization	87,349	70,574	36,674
Loss on asset sales, net	442	113	—
Goodwill impairment	54,199	—	—
Long-lived asset impairment	5,505	—	—
Total costs and expenses	328,268	224,079	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	(14,103)	53,566	43,679
Income tax expense	(631)	(729)	(682)
Net (loss) income	$ (14,734)	$ 52,837	$ 42,997
Less: net income attributable to the pre-IPO period (Note 1)	—	—	24,112
Less: net income attributable to Summit Investments (Note 1)	9,258	9,253	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.

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

	Partners' capital			Summit Investments' equity in contributed subsidiaries	Membership interests	Total
	Limited partners					
	Common	Subordinated	General partner			
	(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

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

	Partners' capital			Summit Investments' equity in contributed subsidiaries	Total
	Limited partners				
	Common	Subordinated	General partner		
			(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	9,253	52,837
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
Consolidation of Polar Midstream net assets	—	—	—	216,105	216,105
Class B membership interest unit-based compensation	17	—	—	830	847
Repurchase of DFW Net Profits Interests	(5,859)	(5,859)	(239)	—	(11,957)
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	72,745	72,745
Capitalized interest allocated to contributed subsidiaries from Summit Investments	—	—	—	2,046	2,046
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	11,964	11,964
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	52	52
Partners' capital, December 31, 2013	566,532	379,287	23,324	523,944	1,493,087

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

	Partners' capital			Summit Investments' equity in contributed subsidiaries	Total
	Limited partners				
	Common	Subordinated	General partner		
			(In thousands)		
Partners' capital, December 31, 2013	566,532	379,287	23,324	523,944	1,493,087
Net (loss) income	(15,948)	(11,169)	3,125	9,258	(14,734)
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	—	—	—	81,421	81,421
Capitalized interest allocated to contributed subsidiaries from Summit Investments	—	—	—	606	606
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	10,483	10,483
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	597	597
Class B membership interest unit-based compensation	—	—	—	340	340
Repurchase of SMLP LTIP units	(228)	—	—	—	(228)
Partners' capital, December 31, 2014	$ 649,060	$ 293,153	$ 24,676	$ 384,832	$ 1,351,721

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

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	$ (14,734)	$ 52,837	$ 42,997
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	88,293	71,606	36,866
Amortization of deferred loan costs	2,770	2,246	1,458
Unit-based compensation	5,036	3,846	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	(19,255)	(20,490)	(8,174)
Due to/from affiliate	(883)	1,427	(773)
Trade accounts payable	(684)	(3,419)	(2,536)
Change in deferred revenue	26,378	16,685	9,994
Ad valorem taxes payable	743	(11)	3,125
Accrued interest	6,714	12,128	(484)
Other, net	1,658	3,501	(383)
Net cash provided by operating activities	154,997	140,469	89,392
Cash flows from investing activities:			
Capital expenditures	(220,820)	(182,978)	(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	(536,367)	(592,393)	(77,296)

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	81,421	72,745	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	10,483	11,964	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	387,517	460,947	(16,224)
Net change in cash and cash equivalents	6,147	9,023	(4,128)
Cash and cash equivalents, beginning of period	20,357	11,334	15,462
Cash and cash equivalents, end of period	$ 26,504	$ 20,357	$ 11,334

Supplemental Cash Flow Disclosures:			
Cash interest paid	$ 31,524	$ 9,016	$ 8,283
Less: capitalized interest	3,778	6,255	2,784
Interest paid (net of capitalized interest)	$ 27,746	$ 2,761	$ 5,499
Cash paid for taxes	$ —	$ 660	$ 650
Noncash Investing and Financing Activities:			
Capital expenditures in trade accounts payable (period-end accruals)	$ 18,076	$ 29,860	$ 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 contributed subsidiaries from Summit Investments	606	2,046	—
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	597	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.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

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.

On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering Company, LLC ("Red Rock Gathering") from a subsidiary of Summit Investments (the "Red Rock Drop Down"). 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, 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. As such, the Red Rock Drop Down 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.

On May 18, 2015, the Partnership acquired certain crude oil and produced water gathering systems and under-development transmission pipelines held by Polar Midstream, LLC ("Polar Midstream") and Epping Transmission Company, LLC ("Epping") located in the Williston Basin (collectively the "Polar and Divide system") from SMP Holdings (the "Polar and Divide Drop Down"). Polar Midstream and Epping are Delaware limited liability companies formed by Summit Investments in April 2014. Polar Midstream's assets were carved out of Meadowlark Midstream immediately prior to the Polar and Divide Drop Down. Concurrent with the closing of the Polar and Divide Drop Down, Epping became a wholly owned subsidiary of Polar Midstream and SMLP contributed Polar Midstream (including Epping) to Bison Midstream. Because the Polar and Divide system was acquired from subsidiaries of Summit Investments, it was deemed a transaction among entities under common control. Common control began in (i) February 2013 for Polar Midstream and (ii) April 2014 for Epping.

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 as well as crude oil and produced water gathering services pursuant to primarily long-term and fee-based agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather, treat, compress and process as well as by the volumes of crude oil and produced water that we gather. Our gathering systems and the unconventional resource basins in which they operate are as follows:

- Mountaineer Midstream, a natural gas gathering system, operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream, an associated natural gas gathering system, operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- the Polar and Divide system ("Polar and Divide"), a crude oil and produced water gathering system and transmission pipelines (under development), operating in the Williston Basin;

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

Our operating subsidiaries, which are wholly owned by our wholly owned subsidiary, Summit Holdings, are: DFW Midstream (which includes Mountaineer Midstream); Bison Midstream (and its wholly owned subsidiaries Polar Midstream and Epping); and Grand River Gathering (and its wholly owned subsidiary Red Rock Gathering). All of our operating subsidiaries are focused on the development, construction and operation of natural gas gathering and processing systems and crude oil and produced water gathering systems.

Presentation and 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, 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 five reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin – Gas, which is served by Bison Midstream;
- the Williston Basin – Liquids, which is served by Polar and Divide;
- 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 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) Polar Midstream since February 16, 2013, (iii) Bison Midstream since February 16, 2013 and (iv) Mountaineer Midstream since June 22, 2013. SMLP recognized its acquisitions of Red Rock Gathering, Polar Midstream and Bison Midstream at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment in Polar Midstream and 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 Red Rock Drop Down, the Polar and Divide 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.

The financial position, results of operations and cash flows of Polar Midstream included herein have been derived from the accounting records of Meadowlark Midstream on a carve-out basis. The majority of the assets and liabilities allocated to Polar Midstream have been specifically identified based on Meadowlark Midstream’s existing divisional organization. Goodwill was allocated to Polar Midstream based on initial purchase accounting estimates. Revenues and depreciation and amortization have been specifically identified based on Polar Midstream's relationship to Meadowlark Midstream’s existing divisional structure. Operation and maintenance and general and administrative expenses have been allocated to Polar Midstream based on volume throughput. These allocations and estimates were based on methodologies that management believes are reasonable. The results reflected herein, however, may not reflect what Polar Midstream’s financial position, results of operations or cash flows would have been if Polar Midstream been a stand-alone company.

Reclassifications. Certain reclassifications have been made to prior-year amounts to conform to current-year presentation. We evaluated our classification of revenues and concluded that creating an “other revenues” category would provide reporting that was more reflective of our results of operations and how we manage our business. As such, certain revenue transactions that represented the “and other” portions of (i) gathering services and (ii) natural gas, NGLs and condensate sales have been reclassified to other revenues. Other revenues also includes the amortization expense associated with our favorable and unfavorable gas gathering contracts. The amounts reclassified to other revenues for each period presented can be determined based on the total of the other revenues line item and the amount of amortization of favorable and unfavorable gas gathering contracts disclosed in Note 5. We also evaluated our historical classification of electricity expense for Bison Midstream. In connection with the reclassification of certain revenues noted above and to be consistent with the classification of pass-through electricity expense for our other operating segments, we reclassified pass-through electricity expenses for Bison Midstream ($5.2 million and $3.1 million for the years ended December 31, 2014 and 2013, respectively) from costs of natural gas and NGLs to operation and maintenance. These reclassifications had no impact on total revenues, total costs and expenses, net income, total partners' capital or segment adjusted EBITDA.

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 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 Polar and Divide Drop Down and the Red Rock Drop Down, a subsidiary of Summit Investments incurred interest expense related to certain Polar and Divide and Red Rock Gathering capital projects. The associated interest expense was allocated to Polar and Divide and 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.

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 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 other revenues.

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-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 gathering, treating and processing services that we provide to our 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 related fees revenue. We also earn revenue from the sale of physical natural gas purchased from our customers under percentage-of-proceeds and keep-whole arrangements. These revenues are recognized in natural gas, NGLs and condensate sales 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; 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, with the revenue component recognized in other revenues.

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 provide natural gas gathering and/or processing services principally under contracts that contain one or more of the following arrangements:

- ***Fee-based arrangements.*** Under fee-based arrangements, we receive a fee or fees for one or more of the following services: 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.

We provide crude oil and produced water gathering services under fee-based arrangements whereby we receive a fee or fees for gathering crude oil and/or produced water.

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.

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 (i) the general partner's 2% interest in net income or loss, (ii) any payments to the general partner in connection with its IDRs and (iii) any net income or loss of contributed subsidiaries that is attributable to Summit Investments, 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, and we are currently unaware of any material contingent liabilities that exist with respect to environmental matters. However, we can provide no assurance that significant costs and liabilities will not be incurred by the Partnership in the future.

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 FASB released a joint revenue recognition standard, Accounting Standards Update ("ASU") No. 2014-09 Revenue From Contracts With Customers (Topic 606) ("ASU 2014-09"). Under ASU 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 Company satisfies a performance obligation. In its original form, ASU 2014-09 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016; early adoption was not permitted. In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of Effective Date ("ASU 2015-14"). ASU 2015-14 defers for one year the effective date of the ASU 2014-09 for both public and nonpublic entities reporting under U.S. GAAP and allows early adoption as of the original effective date. We are currently in the process of evaluating the impact of this update.

In February 2015, the FASB issued ASU No. 2015-02—Consolidation (Topic 810): Amendments to the Consolidation Analysis ("ASU 2015-02"). The standard changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015, and interim and annual periods thereafter. Early adoption is permitted. We are currently in the process of evaluating the impact of this update.

In April 2015, the FASB issued ASU No. 2015-03—Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). Under ASU 2015-03, entities that have historically presented debt issuance costs as an asset, related to a recognized debt liability, will be required to present those costs as a direct deduction from the carrying amount of that debt liability. This presentation will result in debt issuance cost being presented the same way debt discounts have historically been handled. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015, and interim and annual periods thereafter. Early adoption is permitted. We are currently in the process of evaluating the impact of this update.

3. SEGMENT INFORMATION

Each of our reportable segments provides midstream services in a specific geographic area. In the fourth quarter of 2014, we discontinued the aggregation of all of our operating segments. Within specific geographic areas, we may further differentiate reportable segments by type of gathering service provided. In connection with the Polar and Divide Drop Down, we identified two reportable segments in the Williston Basin. We had previously only provided natural gas gathering services in the Williston Basin. With the acquisition of Polar Midstream and Epping in May 2015, we now also provide crude oil and produced water gathering services in the Williston Basin. As such, we evaluated the quantitative and qualitative factors for operating segment aggregation in the Williston Basin and concluded that the characteristics for crude oil and produced water gathering services were not sufficiently similar to those of our natural gas gathering services. As a result, we now report the results of Bison Midstream in the Williston Basin – Gas reportable segment and those of Polar Midstream and Epping in the Williston Basin – Liquids reportable segment.

As of December 31, 2014, our reportable segments are:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin – Gas, which is served by Bison Midstream;
- the Williston Basin – Liquids, which is served by Polar and Divide;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River Gathering.

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 – Gas	311,041	337,610
Williston Basin – Liquids	398,847	307,404
Barnett Shale	428,935	431,578
Piceance Basin	872,437	876,969
Total reportable segment assets	2,255,144	2,167,940
Corporate	38,577	23,203
Total assets	$ 2,293,721	$ 2,191,143

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 – Gas	20,422	16,865	
Williston Basin – Liquids	11,129	485	
Barnett Shale	60,528	69,473	$ 63,670
Piceance Basin	107,953	80,941	53,179
Total reportable segment adjusted EBITDA	$ 215,972	$ 174,097	$ 116,849

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	$ (14,103)	$ 53,566	$ 43,679
Add:			
Interest expense and affiliated interest expense	40,159	19,173	12,766
Depreciation and amortization	88,293	71,606	36,866
Allocated corporate expenses	11,065	8,773	10,903
Adjustments related to MVC shortfall payments	26,565	17,025	10,768
Unit-based compensation	5,036	3,846	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	$ 215,972	$ 174,097	$ 116,849

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 – Gas	62,454	50,735	
Williston Basin – Liquids	22,449	3,893	
Barnett Shale	93,001	105,324	$ 93,453
Piceance Basin	152,537	127,273	81,961
Total reportable segments	353,135	296,813	175,414
Corporate	—	—	(991)
Total revenues	$ 353,135	$ 296,813	$ 174,423
Depreciation and amortization:			
Marcellus Shale	$ 7,648	$ 3,998	
Williston Basin – Gas	18,132	16,057	
Williston Basin – Liquids	4,359	612	
Barnett Shale	15,657	13,929	$ 12,078
Piceance Basin	40,965	35,527	24,310
Total reportable segments	86,761	70,123	36,388
Corporate	588	451	286
Total depreciation and amortization	$ 87,349	$ 70,574	$ 36,674
Other income:			
Marcellus Shale	$ —	$ —	
Williston Basin – Gas	—	—	
Williston Basin – Liquids	—	—	
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 – Gas	46,927	26,381	
Williston Basin – Liquids	92,495	73,602	
Barnett Shale	14,567	29,534	$ 39,588
Piceance Basin	32,505	50,709	36,899
Total reportable segments	220,360	182,048	76,487
Corporate	460	930	809
Total capital expenditures	$ 220,820	$ 182,978	$ 77,296

4. PROPERTY, PLANT, AND EQUIPMENT, NET

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

	Useful lives (In years)	December 31, 2014	December 31, 2013
		(Dollars in thousands)	
Gathering and processing systems and related equipment	30	$ 1,462,706	$ 1,212,227
Construction in progress	n/a	44,447	94,130
Other	4-15	28,871	21,885
Total		1,536,024	1,328,242
Less accumulated depreciation		121,674	71,928
Property, plant, and equipment, net		$ 1,414,350	$ 1,256,314

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 Polar and Divide and Bison Midstream systems. In connection with this evaluation, we also evaluated the property, plant and equipment and intangible assets associated with the Polar and Divide and Bison Midstream systems 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	$ 49,816	$ 37,313	$ 22,422
Capitalized interest	3,778	6,255	2,784

5. IDENTIFIABLE INTANGIBLE ASSETS, UNFAVORABLE GAS GATHERING CONTRACT AND GOODWILL

Intangible Assets and Unfavorable Gas Gathering Contract. Details regarding our intangible assets and the unfavorable gas gathering contract, all of which are subject to amortization, follow.

	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	24.7	123,581	(12,737)	110,844
Total amortizable intangible assets		$ 574,240	$ (96,506)	$ 477,734
Unfavorable gas gathering contract	10.0	$ 10,962	$ (5,385)	$ 5,577

	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	24.7	112,416	(7,758)	104,658
Total amortizable intangible assets		$ 563,075	$ (57,231)	$ 505,844
Unfavorable gas gathering contract	10.0	$ 10,962	$ (4,588)	$ 6,374

We recognized amortization expense in other 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 Polar and Divide and Bison Midstream systems, as discussed below. In connection with this evaluation, we also evaluated the intangible assets and property, plant and equipment associated with the Polar and Divide and Bison Midstream systems 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	4,979	4,607	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	$ 42,254	$ 698
2016	42,219	924
2017	41,069	1,047
2018	40,673	1,123
2019	40,619	957

Goodwill. Recorded goodwill is related to the original acquisitions of the Grand River Gathering, Bison Midstream, Polar and Divide and Mountaineer Midstream systems. The assets acquired in the Polar and Divide Drop Down were carved out of Meadowlark Midstream. As such, we elected to apply the historical cost approach to determine the amount of goodwill to assign to Polar Midstream. Our procedures indicated that the remaining goodwill balance at Meadowlark Midstream was entirely attributable to Polar Midstream. Because Epping was an organic growth project, it has no goodwill. A rollforward of goodwill by reportable segment and in total follows.

	Piceance Basin	Williston Basin – Gas	Williston Basin – Liquids	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 recognized in connection with the Polar and Divide Drop Down	—	—	203,373	—	203,373
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	203,373	16,211	319,261
Goodwill impairment (1)	—	(54,199)	—	—	(54,199)
Goodwill, December 31, 2014	$ 45,478	$ —	$ 203,373	$ 16,211	$ 265,062

(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 Polar Midstream, as included in the Williston Basin – Liquids reportable segment, reporting unit 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 – Gas 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, Polar 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 Polar Midstream and Bison Midstream reporting units did result in an indication that the associated goodwill could have been impaired.

We noted that both reporting units were impacted by the recent price declines. We also noted that a key Bison Midstream customer announced that it was delaying its previously announced drilling plans which caused SMLP to reduce its forecasted volume assumption. The impact of these events increased the likelihood that the goodwill associated with the Polar Midstream and Bison Midstream reporting units could have been impaired. As such, we concluded that a triggering event occurred during the fourth quarter of 2014 requiring that we test the goodwill associated with these reporting units for impairment.

In connection therewith, we reperformed our step one analyses for each as of December 31, 2014. To estimate the fair value of the reporting units, 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;
- 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 Polar Midstream reporting unit substantially exceeded its carrying value, including goodwill as of December 31, 2014. As a result, there was no associated impairment of goodwill in connection with the fourth quarter 2014 triggering event.

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 as of December 31, 2014. 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 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.

A rollforward of current deferred revenue follows.

	Williston Basin – Gas	Barnett Shale	Piceance Basin	Total current
	(In thousands)			
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 – Gas	Barnett Shale	Piceance Basin	Total noncurrent
	(In thousands)			
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	2013
	(In thousands)	
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

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 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.

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
Units issued under SMLP LTIP (1)(2)	46,647	—	861	47,508
Units, December 31, 2014	34,426,513	24,409,850	1,200,651	60,037,014

(1) Including issuance to general partner in connection with contributions made to maintain 2% general partner interest.
(2) Units issued under SMLP LTIP in 2014 is net of 14,300 units withheld to meet minimum statutory tax withholding requirements.

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, pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC. Concurrently, our general partner made a capital contribution to maintain its 2% general partner interest in SMLP. We used the proceeds from the primary offering 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 pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC. We did not receive any proceeds from this offering.

In May 2015, we completed an underwritten public offering of 6,500,000 common units at a price of $30.75 per unit pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC (the "May 2015 Equity Offering"). Concurrent therewith, our general partner made a capital contribution to us to maintain its 2% general partner interest. We used the proceeds from this offering and the general partner capital contribution to fund a portion of the purchase of Polar and Divide.

See Notes 1, 10 and 15 for information on units issued (i) in connection with our IPO, (ii) under the SMLP LTIP plan, and (iii) to fund acquisitions.

Red Rock Drop Down. On March 18, 2014, SMLP acquired 100% of the membership interests in Red Rock Gathering from a subsidiary of Summit Investments. In exchange for its $241.8 million net investment in Red Rock Gathering, SMLP paid total cash consideration of $307.9 million, including working capital adjustments. As a result of the excess of the purchase price over acquired carrying value of Red Rock Gathering, SMLP recognized a capital distribution to Summit Investments. The calculation of the capital distribution and its allocation to partners' capital follow (in thousands).

Summit Investments' net investment in Red Rock Gathering			$	241,817
Total cash consideration paid to a subsidiary of Summit Investments				307,941
Excess of purchase price over acquired carrying value of Red Rock Gathering			$	(66,124)

Allocation of capital distribution:				
General partner interest	$	(1,323)		
Common limited partner interest		(37,910)		
Subordinated limited partner interest		(26,891)		
Partners' capital allocation			$	(66,124)

Bison Drop Down. On June 4, 2013, a subsidiary of Summit Investments entered into a purchase and sale agreement with SMLP whereby SMLP acquired the Bison Gas Gathering system. In exchange for its $305.4 million net investment in Bison Midstream, SMLP paid Summit Investments and the general partner total cash and unit consideration of $248.9 million. As a result of the contribution of net assets in excess of consideration, SMLP recognized a capital contribution from Summit Investments. The details of total cash and unit consideration as well as the calculation of the capital contribution and its allocation to partners' capital follow (dollars in thousands).

Summit Investments' net investment in Bison Midstream			$	305,449
Aggregate cash paid to Summit Investments	$	200,000		
Issuance of 1,553,849 SMLP common units to Summit Investments		47,936		
Issuance of 31,711 SMLP general partner units to the general partner		978		
Total consideration				248,914
Summit Investments' contribution of net assets in excess of consideration			$	56,535

Allocation of capital contribution:				
General partner interest	$	1,131		
Common limited partner interest		28,558		
Subordinated limited partner interest		26,846		
Partners' capital allocation			$	56,535

The number of units issued to Summit Investments and the general partner in connection with the Bison Drop Down was calculated based on an assumed equity issuance of $50.0 million and the five-day volume-weighted-average price as of June 3, 2013 of $31.53 per unit. The units were then valued as of June 4, 2013 (the date of closing) using the June 4, 2013 closing price of SMLP's units of $30.85.

The general partner interest allocation was calculated based on a 2% general partner interest in the contribution of assets in excess of consideration given by SMLP to Summit Investments. Common and subordinated limited partner interests allocations were calculated as their respective percentages of total limited partner capital applied to the balance of the contribution by Summit Investments after giving effect to the general partner allocation.

Mountaineer Acquisition. We completed the acquisition of Mountaineer Midstream on June 21, 2013. The purchase price of $210.0 million was funded with $110.0 million of borrowings under SMLP’s revolving credit facility and the issuance for cash of $100.0 million of SMLP common units and general partner interests to a subsidiary of Summit Investments and the general partner. The allocation and valuation of units issued to partially fund the Mountaineer Acquisition follow (dollars in thousands).

Issuance of 3,107,698 SMLP common units to Summit Investments	$	98,000
Issuance of 63,422 SMLP general partner units to the general partner		2,000
Issuance of units in connection with the Mountaineer Acquisition	$	100,000

Pursuant to a unit purchase agreement, the number of units issued to Summit Investments and the general partner in connection with the Mountaineer Acquisition was calculated based on an assumed equity issuance of $100.0 million and the five-day volume-weighted-average price as of June 3, 2013 of $31.53 per unit.

Subordination. The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution ("MQD," as defined below) plus any arrearages in the payment of the MQD from prior quarters. Subordinated units will not accrue arrearages for unpaid quarterly distributions or quarterly distributions less than the MQD. If we do not pay the MQD on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the MQD to holders of our common units, we will use this excess available cash to pay any distribution arrearages related to prior quarters before any cash distribution is made to holders of subordinated units. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and thereafter no common units will be entitled to arrearages.

The subordination period will end on the first business day after we have earned and paid at least $1.60 (the MQD on an annualized basis) on each outstanding common unit and subordinated unit and the corresponding distribution on the general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015.

Cash Distribution Policy

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. Our partnership agreement requires that we distribute all of our available cash (as defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the MQD stated in our partnership agreement.

Minimum Quarterly Distribution. Our partnership agreement generally requires that we make a minimum quarterly distribution to the holders of our common units and subordinated units of $0.40 per unit, or $1.60 on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. The amount of distributions paid under our policy is subject to fluctuations based on the amount of cash we generate from our business and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

Definition of Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner at the date of determination of available cash for that quarter to:
  - provide for the proper conduct of our business (including reserves for our future capital expenditures and anticipated future debt service requirements);
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner's initial 2.0% interest in our distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentage allocations, up to a maximum of 50.0% (as set forth in the chart below), of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general partner interest at 2.0%. The maximum distribution does not include any distributions that our general partner may receive on any common or subordinated units that it owns.

Percentage Allocations of Available Cash. The following table illustrates the percentage allocations of available cash between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth in the column Marginal Percentage Interest in Distributions are the percentage interests of our general partner and the unitholders in any available cash we distribute up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit Target Amount. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its 2.0% general partner interest, our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total quarterly distribution per unit target amount	Marginal percentage interest in distributions	
		Unitholders	General partner
Minimum quarterly distribution	$0.40	98.0%	2.0%
First target distribution	$0.40 up to $0.46	98.0%	2.0%
Second target distribution	above $0.46 up to $0.50	85.0%	15.0%
Third target distribution	above $0.50 up to $0.60	75.0%	25.0%
Thereafter	above $0.60	50.0%	50.0%

Details of cash distributions declared to date follow.

Attributable to the quarter ended	Payment date	Per-unit distribution	Cash paid to common unitholders	Cash paid to subordinated unitholders	Cash paid to general partner	Cash paid for IDRs	Total distribution
			(In thousands, except per-unit amounts)				
December 31, 2012	February 14, 2013	$ 0.4100	$ 10,009	$ 10,008	$ 408	$ —	$ 20,425
March 31, 2013	May 15, 2013	0.4200	10,253	10,252	418	—	20,923
June 30, 2013	August 14, 2013	0.4350	12,647	10,618	475	—	23,740
September 30, 2013	November 14, 2013	0.4600	13,377	11,229	502	—	25,108
December 31, 2013	February 14, 2014	0.4800	13,958	11,717	528	163	26,366
March 31, 2014	May 15, 2014	0.5000	17,211	12,205	607	360	30,383
June 30, 2014	August 14, 2014	0.5200	17,900	12,693	639	721	31,953
September 30, 2014	November 14, 2014	0.5400	18,589	13,181	670	1,082	33,522

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 was paid on February 13, 2015 to unitholders of record at the close of business on February 6, 2015. SMLP allocated its distribution in accordance with the third target distribution level for distributions attributable to the quarter ended December 31, 2014.

Membership Interests

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of Polar and Divide, Red Rock Gathering and Bison Midstream that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for Polar and Divide, Red Rock Gathering and Bison Midstream for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. During the years ended December 31, 2014 and December 31, 2013, net income was attributed to Summit Investments for (i) Polar and Divide for the years ended December 31, 2014 and 2013 (ii) Red Rock Gathering for the period from January 1, 2014 to March 18, 2014, for the year ended December 31, 2013 and for the period from October 23, 2012 to December 31, 2012 and (iii) Bison Midstream for the period from February 16, 2013 to June 4, 2013. Although included in partners' capital, net income attributable to Summit Investments has been excluded from the calculation of EPU for the years ended December 31, 2014 and 2013 and for the period from October 1, 2012 to December 31, 2012.

Predecessor Membership Interests. Holders of membership interests in Summit Investments participate in distributions and exercise the other rights or privileges available to each entity under Summit Investments' Fourth Amended and Restated Limited Liability Operating Agreement (the "Summit LLC Agreement"). In accordance with the Summit LLC Agreement, capital accounts are maintained for Summit Investments' members. The capital account provisions of the Summit LLC Agreement incorporate principles established for U.S. federal income tax purposes and as such are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

The Summit LLC Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that its membership interest holders will receive. Capital contributions required under the Summit LLC Agreement are in proportion to the members' respective percentage ownership interests. The Summit LLC Agreement also contains provisions for the allocation of net earnings and losses to members. For purposes of maintaining partner capital accounts, the Summit LLC Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests.

9. EARNINGS PER UNIT

The following table presents details on EPU.

	Year ended December 31,		
	2014	2013	2012 (1)
	(In thousands, except per-unit amounts)		
Net (loss) income	$ (14,734)	$ 52,837	$ 42,997
Less: net income attributable to the pre-IPO period	—	—	24,112
Less: net income attributable to Summit Investments	9,258	9,253	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
Numerator for basic and diluted EPU:			
Allocation of net (loss) income among limited partner interests:			
Net (loss) income attributable to common units	$ (16,324)	$ 23,227	$ 8,632
Net (loss) income attributable to subordinated units	(10,793)	19,322	8,630
Net (loss) income attributable to limited partners	$ (27,117)	$ 42,549	$ 17,262
Denominator for basic and diluted EPU:			
Weighted-average common units outstanding – basic	33,311	26,951	24,412
Effect of nonvested phantom units	—	150	132
Weighted-average common units outstanding – diluted	33,311	27,101	24,544
Weighted-average subordinated units outstanding – basic and diluted	24,410	24,410	24,410
(Loss) earnings per limited partner unit:			
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

(1) Calculated for the period from October 1, 2012 to December 31, 2012

Our general partner was not entitled to receive incentive distributions for periods prior to the fourth quarter of 2013 based on the amount of the distributions declared per common and subordinated unit. During the year ended December 31, 2014, we excluded 231,875 units from the calculation of diluted loss per common unit because their impact was anti-dilutive. There were no units excluded from the calculation of diluted earnings per common unit as we did not have any anti-dilutive units for the year ended December 31, 2013 or for the period from October 1, 2012 to December 31, 2012.

10. UNIT-BASED COMPENSATION

SMLP Long-Term Incentive Plan. The SMLP Long-Term Incentive Plan (the "SMLP LTIP") provides for equity awards to eligible officers, employees, consultants and directors of our general partner and its affiliates, thereby linking the recipients' compensation directly to SMLP’s performance. The SMLP LTIP is administered by our general partner's board of directors, though such administration function may be delegated to a committee appointed by the board. A total of 5.0 million common units was reserved for issuance pursuant to and in accordance with the SMLP LTIP. As of December 31, 2014, approximately 4.6 million common units remained available for future issuance.

The SMLP LTIP provides for the granting, from time to time, of unit-based awards, including common units, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Grants are made at the discretion of the board of directors or compensation committee of our general partner. The administrator of the SMLP LTIP may make grants under the SMLP LTIP that contain such terms, consistent with the SMLP LTIP, as the administrator may determine are appropriate, including vesting conditions. The administrator of the SMLP LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the SMLP LTIP) or as otherwise described in an award agreement. Termination of employment prior to vesting will result in forfeiture of the awards, except in limited circumstances as described in the plan documents. Units that are canceled or forfeited will be available for delivery pursuant to other awards.

The following table presents phantom and restricted unit activity:

	Units	Weighted-average grant date fair value
Nonvested phantom and restricted units, January 1, 2012	—	$ —
Phantom units granted	125,000	20.00
Restricted units granted	6,558	20.23
Nonvested phantom and restricted units, December 31, 2012	131,558	20.00
Phantom units granted	155,330	26.33
Restricted units granted	835	27.50
Phantom units forfeited	(4,041)	25.99
Nonvested phantom and restricted units, December 31, 2013	283,682	23.41
Phantom units granted	136,867	42.32
Phantom and restricted units vested	(61,917)	25.33
Phantom units forfeited	(22,430)	25.56
Nonvested phantom units, December 31, 2014	336,202	$ 30.61

A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. Distribution equivalent rights for each phantom unit provide for a lump sum cash amount equal to the accrued distributions from the grant date to be paid in cash upon the vesting date. A restricted unit is a common limited partner unit that is subject to a restricted period during which the unit remains subject to forfeiture.

The phantom units granted in connection with the IPO vest on the third anniversary of the IPO. All other phantom units granted to date vest ratably over a three-year period. Grant date fair value is determined based on the closing price of our common units on the date of grant multiplied by the number of phantom units awarded to the grantee. Holders of all phantom units granted to date are entitled to receive distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. Upon vesting, phantom unit awards may be settled, at our discretion, in cash and/or common units, but the current intention is to settle all phantom unit awards with common units. The restricted units granted in 2013 and 2012 maintained the vesting provisions of the share-based compensation awards they replaced, each of which had an original vesting period of four years. See "—DFW Net Profits Interests" below for additional information.

As of December 31, 2014, the unrecognized unit-based compensation related to the SMLP LTIP was $4.1 million. Incremental unit-based compensation will be recorded over the remaining vesting period of approximately 2.25 years. Due to the limited and immaterial forfeiture history associated with the grants under the SMLP LTIP, no forfeitures were assumed in the determination of estimated compensation expense.

Unit-based compensation recognized in general and administrative expense related to awards under the SMLP LTIP was as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
SMLP LTIP unit-based compensation	$ 4,696	$ 2,999	$ 269

DFW Net Profits Interests. In connection with the formation of DFW Midstream in 2009, up to 5% of DFW Midstream's total membership interests were authorized for issuance (the "DFW Net Profits Interests"). Grants were made in 2009 and 2010. Beginning in October 2012 and continuing into April 2013, we entered into a series of repurchases with the remaining seven holders of the then-outstanding DFW Net Profits Interests whereby we exchanged $12.2 million for their vested DFW Net Profits Interests and 7,393 SMLP restricted units for their unvested DFW Net Profits Interests. The repurchase prices were determined by valuing the vested and unvested net profits interests in relation to the enterprise value of DFW Midstream and represented fair value at the dates of repurchase. Upon the conclusion of these repurchase transactions, there were no remaining or outstanding DFW Net Profits Interests.

The DFW Net Profits Interests participated in distributions upon time vesting and the achievement of certain distribution targets and were accounted for as compensatory awards. Each grant vested ratably over four years and provided for accelerated vesting in certain limited circumstances.

We determined the fair value of the DFW Net Profits Interests with assistance from a third-party valuation expert. The DFW Net Profits Interests were valued utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of DFW Midstream and considered the rights and preferences of each class of equity to allocate a fair value to each class. A significant input of the option pricing method was the enterprise value of DFW Midstream. We estimated the enterprise value utilizing a combination of the income and market approaches. Additional significant inputs used in the option pricing method included the length of holding period, discount for lack of marketability and volatility. Information regarding the vested and nonvested DFW Net Profits Interests were as follows:

	Year ended December 31,			
	2013		2012	
	Percentage Interest	Weighted-average grant date fair value (per 1.0% of DFW Net Profits Interest)	Percentage Interest	Weighted-average grant date fair value (per 1.0% of DFW Net Profits Interest)
	(Dollars in thousands)			
Nonvested, beginning of period	0.038%	$ 1,650	1.750%	$ 306
Repurchased	0.038%	$ 1,650	0.000%	$ —
Vested	0.000%	$ —	1.644%	$ 256
Forfeited	0.000%	$ —	0.069%	$ 765
Nonvested, end of period	0.000%	$ —	0.038%	$ 1,650
Vested, end of period	0.000%	$ —	4.294%	$ 257

We recognized noncash compensation expense related to the DFW Net Profits Interests within general and administrative expense of $17 thousand for the year ended December 31, 2013 and $0.7 million for the year ended December 31, 2012.

SMP Net Profits Interests. In connection with the formation of Summit Investments in 2009, up to 7.5% of total membership interests were authorized for issuance. SMP Net Profits Interests participate in distributions upon time vesting and the achievement of certain distribution targets. The SMP Net Profits Interests are accounted for as compensatory awards. Additional SMP Net Profits Interests were granted through January 2012. All grants vest ratably over five years and provide for accelerated vesting in certain limited circumstances, including a qualifying termination following a change in control. As of December 31, 2012, 6.355% of SMP Net Profits Interests had been granted to certain members of management, and no SMP Net Profits Interests had been forfeited. The SMP Net Profits Interests were retained by the Predecessor and as such are not reflected in SMLP's financial statements subsequent to the IPO, except as noted below.

We determined the fair value of the SMP Net Profits Interests as of the respective grant dates with assistance from a third-party valuation expert. We valued the SMP Net Profits Interests utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of Summit Investments and considered the rights and preferences of each class of equity to allocate a fair value to each class.

A significant input of the option pricing method is the enterprise value of Summit Investments. We estimated enterprise value utilizing a combination of the income and market approaches. The income approach utilized the discounted cash flow method, whereby we applied a discount rate to estimated future cash flows of Summit Investments. Under the market approach, we applied trading multiples of the securities of publicly-traded peer companies to Summit Investments' estimated future cash flows.

Additional significant inputs used in the option pricing method included length of holding period, discount for lack of marketability and volatility. The length of holding period was primarily determined based upon our Sponsors' expectations as of the grant date. We estimated the discount for lack of marketability and volatility with assistance from a third-party valuation firm. We estimated the discount for lack of marketability using a protective put methodology. The protective put methodology consisted of estimating the cost to insure an investment in the SMP Net Profits Interests over the length of the holding period. We estimated the expected volatility of the SMP Net Profits Interests based on the historical and implied volatilities of the securities of publicly-traded peer companies. We estimated historical volatility based on daily stock price returns over a look-back period commensurate with the length of the holding period for each grant of SMP Net Profits Interests. We estimated implied volatility based on the average implied volatility of the publicly-traded peer companies using data from Standard & Poor's Capital IQ proprietary research tool. We based the expected volatility conclusions on consideration of both the historical and implied volatilities of the publicly-traded peer companies as of the various grant dates.

The inputs used in the option pricing method for the SMP Net Profits Interests granted during the year ended December 31, 2012 were as follows:

	January 2012 grant
Length of holding period restriction (In years)	2.93
Discount for lack of marketability	24.0%
Volatility	37.0%

Information regarding the amount and grant-date fair value of the vested and nonvested SMP Net Profits Interests for the period in which they were reflected in our financial results follows.

	Year ended December 31,	
	2012	
	Percentage Interest	**Weighted-average grant date fair value (per 1.0% of SMP Net Profits Interest)**
	(Dollars in thousands)	
Nonvested, beginning of period	3.958%	$ 1,003
Granted	0.500%	$ 1,780
Vested	1.271%	$ 965
Nonvested, end of period (1)	3.187%	$ 1,140
Vested, end of period	3.168%	$ 788

(1) Subsequent to the IPO, the vested and nonvested net profits interests are obligations of the Predecessor and not the Partnership

We recognized noncash compensation expense related to the SMP Net Profits Interests in general and administrative expense of $0.3 million for the year ended December 31, 2014, $0.8 million for the year ended December 31, 2013 and $0.9 million for the year ended December 31, 2012. For the year ended December 31, 2014 the expense reflects amounts allocated to Polar and Divide prior to the Polar and Divide Drop Down. For the year ended December 31, 2013, the expense reflects amounts allocated to Polar and Divide and Red Rock Gathering by Summit Investments prior to the Polar and Divide Drop Down and Red Rock Drop Down. For the year ended December 31, 2012, the expense reflects amounts attributable to the Predecessor prior to our IPO.

11. CONCENTRATIONS OF RISK

Financial instruments that potentially subject us to concentrations of credit risk consist of cash and accounts receivable. We maintain our cash in bank deposit accounts that frequently exceed federally insured limits. We have not experienced any losses in such accounts and do not believe we are exposed to any significant risk.

Accounts receivable primarily comprise amounts due for the gathering, treating and processing services we provide to our customers and also the sale of natural gas liquids resulting from our processing services. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of our counterparties and can require letters of credit for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated.

Counterparties accounting for more than 10% of total revenues were as follows:

	Year ended December 31,		
	2014	2013	2012
Revenue:			
Counterparty A - Piceance Basin	20%	21%	27%
Counterparty B - Barnett Shale	*	15%	19%
Counterparty C - Williston Basin – Gas	*	*	—%
Counterparty D - Marcellus Shale	*	*	—%
Counterparty E - Piceance Basin	*	*	—%
Counterparty F - Barnett Shale	*	*	14%

** Less than 10%*

Counterparties accounting for more than 10% of total accounts receivable were as follows:

	December 31,	
	2014	2013
Accounts receivable:		
Counterparty A - Piceance Basin	27%	36%
Counterparty B - Barnett Shale	*	10%
Counterparty C - Williston Basin – Gas	13%	*
Counterparty D - Marcellus Shale	*	*
Counterparty E - Piceance Basin	*	*
Counterparty F - Barnett Shale	*	*

** Less than 10%*

12. RELATED-PARTY TRANSACTIONS

Recent Acquisitions. See Notes 1, 8 and 15 for disclosure of the Polar and Divide Drop Down, the Red Rock Drop Down, the Bison Drop Down and the funding of those transactions.

Reimbursement of Expenses from General Partner. Our general partner and its affiliates do not receive a management fee or other compensation in connection with the management of our business, but will be reimbursed for expenses incurred on our behalf. Under our partnership agreement, we reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers who perform services necessary to run our business. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Due to affiliate on the consolidated balance sheet represents the payables to our general partner for expenses incurred by it and paid on our behalf.

Expenses incurred by the general partner and reimbursed by us under our partnership agreement were as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Operation and maintenance expense	$ 19,782	$ 14,323	$ 2,913
General and administrative expense	22,370	18,662	3,661

Expenses Incurred by Summit Investments. Prior to the Polar and Divide Drop Down and the Red Rock Drop Down, Summit Investments incurred:

- certain support expenses and capital expenditures on behalf of the contributed subsidiaries. These transactions were settled periodically through membership interests prior to the respective drop down;
- interest expense that was related to capital projects for the contributed subsidiaries. As such, the associated interest expense was allocated to the respective contributed subsidiary's capital projects as a noncash contribution and capitalized into the basis of the asset; and
- SMP Net Profits Interests accounted for as compensatory awards. As such, the annual expense associated with the SMP Net Profits was allocated to the respective contributed subsidiary and is reflected in general and administrative expenses in the statement of operations.

Electricity Management Services Agreement. We entered into a consulting arrangement with EquiPower Resources Corp. to assist with managing DFW Midstream's electricity price risk. EquiPower Resources Corp. is an affiliate of Energy Capital Partners and is also the employer of a director of our general partner. Amounts paid for such services were as follows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Payments for electricity management consulting services	$ 234	$ 199	$ 204

The consulting arrangement terminated on December 31, 2014.

Engineering Services Agreement. We entered into an engineering services arrangement with IPS Engineering/EPC. IPS Engineering/EPC is an affiliate of Energy Capital Partners. We paid $0.6 million for such services during the year ended December 31, 2014 and $0.2 million for such services during the year ended December 31, 2013.

Promissory Notes Payable to Sponsors. In conjunction with the acquisition of Grand River Gathering in 2011, we executed $200.0 million of promissory notes, on an unsecured basis, with the Sponsors. The notes had an 8% interest rate and were scheduled to mature in October 2013. In May 2012, we borrowed $163.0 million under the revolving credit facility and used a portion of the same borrowings to prepay $160.0 million principal amount of the promissory notes payable to the Sponsors. Then in July 2012, we borrowed an additional $50.0 million under the revolving credit facility, a portion of which was used to pay the remaining $49.2 million principal amount of the promissory notes payable to Sponsors (inclusive of accrued pay-in-kind interest).

In accordance with the terms of the underlying note agreement, prior to their repayment in July 2012, we elected to make all interest payments on the note in kind. The amount of interest paid in kind and accrued to the balance of the notes for year ended December 31, 2012, was approximately $6.3 million, of which we capitalized $0.9 million of interest expense related to costs incurred on capital projects under construction.

Diligence Expenses. In the past, the Sponsors reimbursed Summit Investments for transactional due diligence expenses related to proposed transactions that were not completed. As of December 31, 2011, we had a receivable from the Sponsors of $1.3 million for similar expenses. During the year ended December 31, 2012, we were reimbursed $0.3 million, while $1.0 million was not paid.

13. BENEFIT PLAN

We have a defined contribution benefit plan for our employees. The expense associated with this plan was approximately $0.9 million in 2014, $0.6 million in 2013, and $0.2 million in 2012.

14. COMMITMENTS AND CONTINGENCIES

Operating Leases. We and Summit Investments lease certain office space to support our operations. We have determined that our leases are operating leases. We recognize total rent expense incurred or allocated to us in general and administrative expenses. Rent expense related to operating leases, including rent expense incurred on our behalf and allocated to us, was as follows:

	Year ended December 31,		
	2014	2013	2012
Rent expense	$ 1,786	$ 1,495	$ 732

Future minimum lease payments for the Partnership's operating leases are immaterial.

Legal Proceedings. The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims or those arising in the normal course of business would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

15. ACQUISITIONS

Polar and Divide. On May 18, 2015, SMLP acquired the Polar and Divide system from a subsidiary of Summit Investments, subject to customary working capital and capital expenditures adjustments. We funded the initial combined purchase price of $290.0 million with (i) $92.5 million of borrowings under SMLP’s revolving credit facility and (ii) the issuance of $193.4 million of SMLP common units and $4.1 million of general partner interests to SMLP’s general partner in connection with the May 2015 Equity Offering.

Summit Investments accounted for its purchase of Meadowlark Midstream, the entity that Polar Midstream was carved out of, under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible and intangible assets acquired and liabilities assumed were recorded based on their fair values as of initial acquisition on February 15, 2013. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the system. We recognized the acquisition of Polar Midstream at Summit Investments' historical cost of construction and fair value of assets and liabilities at acquisition, which reflected its fair value accounting for the acquisition of Meadowlark Midstream, due to common control. The fair values of the assets acquired and liabilities assumed as of February 15, 2013, were as follows (in thousands):

Purchase price assigned to Polar Midstream		$ 216,105
Current assets	$ 368	
Property, plant, and equipment	9,755	
Other noncurrent assets	7,201	
Total assets acquired	17,324	
Current liabilities	4,592	
Total liabilities assumed	$ 4,592	
Net identifiable assets acquired		12,732
Goodwill		$ 203,373

We believe that the goodwill recorded represents the incremental value of future cash flow potential attributed to estimated future gathering services within the Williston Basin.

Red Rock Gathering System. On March 18, 2014, the Partnership acquired Red Rock Gathering from a subsidiary of Summit Investments, subject to customary working capital adjustments. The Partnership paid total cash consideration of $307.9 million, comprising $305.0 million at the date of acquisition and $2.9 million of working capital adjustments that were recognized in due to affiliate as of December 31, 2014 and settled in February 2015. The acquisition of Red Rock Gathering was funded with the net proceeds from an offering of common units in March 2014, $100.0 million of borrowings under our revolving credit facility and cash on hand. Because of the common control aspects in the drop down transaction, the Red Rock Gathering acquisition was deemed a transaction between entities under common control and, as such, was accounted for on an “as-if pooled” basis for all periods in which common control existed. SMLP’s financial results retrospectively include Red Rock Gathering’s financial results for all periods ending after October 23, 2012, the date Summit Investments acquired its interests, and before March 18, 2014.

Summit Investments acquired the natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin in western Colorado and eastern Utah that comprise the Red Rock Gathering system from a subsidiary of Energy Transfer Partners, L.P. in September 2012 for $206.7 million. Summit Investments' acquisition of the Red Rock Gathering system closed on October 23, 2012. Summit Investments accounted for its acquisition of Red Rock Gathering under the acquisition method of accounting. Red Rock Gathering's identifiable tangible and intangible assets acquired and liabilities assumed were recognized at their fair values as of October 23, 2012. The intangible assets that were acquired comprised right-of-way easements with a life of 20 years upon acquisition. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the Red Rock Gathering system. The final fair values of the assets acquired and liabilities assumed as of October 23, 2012, were as follows (in thousands):

Red Rock Gathering purchase price		$ 206,694
Cash	$ 1,097	
Accounts receivable	8,018	
Other assets	317	
Property, plant, and equipment	150,401	
Rights-of-way	52,197	
Other noncurrent assets	164	
Total assets acquired	212,194	
Trade accounts payable	2,558	
Other current liabilities	2,942	
Total liabilities assumed	$ 5,500	
Net identifiable assets acquired		$ 206,694

During the fourth quarter of 2014, we identified and wrote off the balance associated with a working capital adjustment received after the purchase accounting measurement period closed for Summit Investments' acquisition of Red Rock Gathering. This write off was recognized as a $1.2 million increase to gathering services and other fees for the year ended December 31, 2014.

Lonestar Assets. DFW Midstream completed the acquisition of certain natural gas gathering assets located in the Barnett Shale Play ("Lonestar") from Texas Energy Midstream, L.P. ("TEM") for $10.9 million on September 30, 2014. The Lonestar assets gather natural gas under two long-term, fee-based contracts. SMLP is accounting for the purchase under the acquisition method of accounting. As of September 30, 2014, we preliminarily assigned the full purchase price to property, plant and equipment. During the fourth quarter of 2014, we received additional information from TEM and finalized the purchase price allocation.

Bison Gas Gathering System. On February 15, 2013, Summit Investments acquired BTE. On June 4, 2013, a subsidiary of Summit Investments entered into a purchase and sale agreement with SMLP whereby SMLP acquired the Bison Gas Gathering system. The Bison Gas Gathering system was carved out from Meadowlark Midstream and primarily gathers associated natural gas production from customers operating in Mountrail and Burke counties in North Dakota under long-term contracts ranging from five years to 15 years. The weighted-average life of the acquired contracts was 12 years upon acquisition.

Summit Investments accounted for its purchase of BTE (the "BTE Transaction") under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible and intangible assets acquired and liabilities assumed were recorded based on their fair values as of February 15, 2013. The intangible assets that were acquired are composed of gas gathering agreement contract values and rights-of-way easements. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the system.

Because the Bison Drop Down was executed between entities under common control, SMLP recognized the acquisition of the Bison Gas Gathering system at historical cost which reflected Summit Investments fair value accounting for the BTE Transaction. Furthermore, due to the common control aspect, the Bison Drop Down was accounted for by SMLP on an “as-if pooled” basis for all periods in which common control existed. Common control began on February 15, 2013 concurrent with the BTE Transaction.

The fair values of the assets acquired and liabilities assumed as of February 15, 2013, were as follows (in thousands):

Purchase price assigned to Bison Gas Gathering system		$ 303,168
Current assets	$ 5,705	
Property, plant, and equipment	85,477	
Intangible assets	164,502	
Other noncurrent assets	2,187	
Total assets acquired	257,871	
Current liabilities	6,112	
Other noncurrent liabilities	2,790	
Total liabilities assumed	$ 8,902	
Net identifiable assets acquired		248,969
Goodwill		$ 54,199

The Bison Drop Down closed on June 4, 2013. The total acquisition purchase price of $248.9 million was funded with $200.0 million of borrowings under SMLP’s revolving credit facility and the issuance of $47.9 million of SMLP common units to Summit Investments and $1.0 million of general partner interests to SMLP’s general partner. Summit Investments had a net investment in the Bison Gas Gathering system of $303.2 million and received total consideration of $248.9 million from SMLP. As a result, SMLP recognized a capital contribution from Summit Investments for the contribution of net assets in excess of consideration paid.

Mountaineer Midstream. We completed the acquisition of Mountaineer Midstream from MarkWest for $210.0 million on June 21, 2013. The Mountaineer Midstream natural gas gathering and compression assets are located in the Appalachian Basin which includes the Marcellus Shale formation primarily in Doddridge and Harrison counties in northern West Virginia. The Mountaineer Midstream system consists of newly constructed, high-pressure gas gathering pipelines, certain rights-of-way associated with the pipeline, and two compressor stations. The assets gather natural gas under a long-term, fee-based contract with Antero Resources Corp. ("Antero"). The life of the acquired contract was 13 years upon acquisition.

The Mountaineer Acquisition was funded with $110.0 million of borrowings under the Partnership's revolving credit agreement and the issuance of $100.0 million of common and general partner interests to a subsidiary of Summit Investments. For the year ended December 31, 2013, SMLP recorded $9.6 million of revenue and $2.3 million of net income related to Mountaineer Midstream.

SMLP accounted for the Mountaineer Acquisition under the acquisition method of accounting. As of June 30, 2013, we preliminarily assigned the full $210.0 million purchase price to property plant and equipment. During the third quarter of 2013, we received additional information and, as a result, preliminarily assigned $158.3 million of the purchase price to property, plant and equipment, $27.1 million to contract intangibles, $6.5 million to rights-of-way and $18.1 million to goodwill. During the fourth quarter of 2013, we received additional information from MarkWest and finalized the purchase price allocation.

The final fair values of the assets acquired and liabilities assumed as of June 21, 2013, were as follows (in thousands):

Purchase price assigned to Mountaineer Midstream		$ 210,000
Property, plant, and equipment	$ 163,661	
Gas gathering agreement contract intangibles	24,019	
Rights-of-way	6,109	
Total assets acquired	193,789	
Total liabilities assumed	$ —	
Net identifiable assets acquired		193,789
Goodwill		$ 16,211

Grand River Gathering. During the fourth quarter of 2014, we identified and wrote off certain balances previously recognized in connection with the Predecessor's purchase accounting for Grand River Gathering. This write off was recognized as a $1.2 million increase to other income.

Supplemental Disclosures – As-If Pooled Basis. As a result of accounting for our drop down transactions similar to a pooling of interests, our historical financial statements and those of Polar Midstream, Epping, Red Rock Gathering and the Bison Gas Gathering system have been combined to reflect the historical operations, financial position and cash flows from the date common control began. Revenues and net income for the previously separate entities and the combined amounts, as presented in these consolidated financial statements follow.

	Year ended December 31,		
	2014	2013	2012
		(In thousands)	
SMLP revenues	$ 319,373	$ 225,192	$ 165,499
Polar and Divide revenues	22,449	3,893	
Red Rock Gathering revenues	11,313	50,114	8,924
Bison Gas Gathering system revenues (1)		17,614	
Combined revenues	$ 353,135	$ 296,813	$ 174,423
SMLP net (loss) income	$ (23,992)	$ 43,584	$ 41,726
Polar and Divide net income (loss)	6,430	(467)	
Red Rock Gathering net income	2,828	9,668	1,271
Bison Gas Gathering system net income (1)		52	
Combined net (loss) income	$ (14,734)	$ 52,837	$ 42,997

(1) Results are fully reflected in SMLP's results of operations for the year ended December 31, 2014.

Unaudited Pro Forma Financial Information. The following unaudited pro forma financial information assumes that:

- Any pro forma adjustments for the acquisition of Polar and Divide are not material because (i) the system, which is still under development, was not operational until May 2013 and (ii) all financial results have been reflected.
- The acquisition of Red Rock Gathering occurred on January 1, 2011. The pro forma results reflect actual Red Rock Gathering revenues and net income earned and recognized in 2014 and 2013, and by annualizing the actual operating results for Red Rock Gathering that were recorded in 2012 for the year ended December 31, 2012.
- The acquisition of the Bison Gas Gathering system occurred on January 1, 2012. The pro forma results for Bison Midstream were derived from revenues and net income in 2013 and 2012.
- The acquisition of Mountaineer Midstream occurred on January 1, 2012. The pro forma results for Mountaineer Midstream were derived from revenues and net income in 2013. Mountaineer Midstream was not operational until November 2012.

- The acquisition of the Lonestar assets is immaterial for pro forma purposes and as such has not been reflected below.
- Pro forma net income for the year ended December 31, 2014 has been adjusted to remove the impact of $0.7 million of nonrecurring transaction costs associated with the acquisition of Red Rock Gathering.
- Pro forma net income for the year ended December 31, 2013 has been adjusted to remove the impact of $2.5 million of nonrecurring transaction costs associated with the acquisitions of Bison Midstream and Mountaineer Midstream.
- Pro forma net income for the year ended December 31, 2012 has been adjusted to remove the impact of $1.6 million of nonrecurring transaction costs associated with the acquisition of Red Rock Gathering.
- Pro forma adjustments in 2014, 2013 and 2012 also reflect the impact of a 5,300,000 common unit issuance, the general partner capital contribution to maintain its 2% general partner interest and $100.0 million of incremental borrowings on our revolving credit facility to fund the acquisition of Red Rock Gathering.
- Pro forma adjustments in 2014, 2013 and 2012 also reflect the impact of 4,661,547 common unit issuance and the general partner capital contribution to maintain its 2% general partner interest to fund the acquisition of Bison Midstream and Mountaineer Midstream.
- Pro forma adjustments in 2013 and 2012 also reflect the impact of $310.0 million of incremental borrowings on our revolving credit facility for the Bison Midstream and Mountaineer Midstream acquisitions and incremental depreciation and amortization expense associated with the acquired property, plant and equipment and contract intangibles as a result of the application of fair value accounting for Bison Midstream.

	Year ended December 31,		
	2014	2013	2012
	(In thousands, except for per-unit amounts)		
Total Polar and Divide revenues included in consolidated revenues	$ 22,449	$ 3,893	
Total Red Rock Gathering revenues included in consolidated revenues	73,266	50,114	$ 8,924
Total Bison Midstream and Mountaineer Midstream revenues included in consolidated revenues		60,323	
Total Polar and Divide net income (loss) included in consolidated net income	$ 6,430	$ (467)	
Total Red Rock Gathering net income included in consolidated net income	27,447	9,668	$ 1,271
Total Bison Midstream and Mountaineer Midstream net loss included in consolidated net income		(457)	
Pro forma total revenues	$ 353,135	$ 308,964	$ 256,637
Pro forma net (loss) income	(14,508)	46,904	38,639
Pro forma common EPU - basic and diluted	$ (0.30)	$ 0.78	$ 0.28
Pro forma subordinated EPU - basic and diluted	(0.30)	0.78	0.28

The unaudited pro forma financial information presented above is not necessarily indicative of (i) what our financial position or results of operations would have been if the acquisitions of Polar and Divide, Bison Midstream and Mountaineer Midstream had occurred on January 1, 2012 or if the acquisition of Red Rock Gathering had occurred on January 1, 2011, or (ii) what SMLP’s financial position or results of operations will be for any future periods.

16. UNAUDITED QUARTERLY FINANCIAL DATA

Summarized information on the consolidated results of operations for each of the quarters during the two-year period ended December 31, 2014, follows.

	Quarter ended December 31, 2014	Quarter ended September 30, 2014	Quarter ended June 30, 2014	Quarter ended March 31, 2014
	(In thousands, except per-unit amounts)			
Total revenues (1)	$ 102,986	$ 84,784	$ 85,984	$ 79,381
Net (loss) income attributable to partners (2)	$ (37,686)	$ 6,113	$ 4,036	$ 3,545
Less: net (loss) income attributable to general partner, including IDRs	689	1,204	801	431
Net (loss) income attributable to limited partners	$ (38,375)	$ 4,909	$ 3,235	$ 3,114
(Loss) earnings per limited partner unit:				
Common unit – basic	$ (0.65)	$ 0.08	$ 0.05	$ 0.08
Common unit – diluted	$ (0.65)	$ 0.08	$ 0.05	$ 0.08
Subordinated unit – basic and diluted	$ (0.65)	$ 0.08	$ 0.05	$ 0.02

(1) Retrospectively adjusted for the impact of the Polar and Divide Drop Down.
(2) In the quarter ended December 31, 2014, includes $54.2 million of goodwill impairment and $5.5 million of long-lived asset impairment.

	Quarter ended December 31, 2013	Quarter ended September 30, 2013	Quarter ended June 30, 2013	Quarter ended March 31, 2013
	(In thousands, except per-unit amounts)			
Total revenues (1)	$ 85,599	$ 77,353	$ 71,847	$ 62,014
Net income attributable to partners	$ 16,345	$ 6,691	$ 8,068	$ 12,480
Less: net income attributable to general partner, including IDRs	490	134	161	250
Net income attributable to limited partners	$ 15,855	$ 6,557	$ 7,907	$ 12,230
Earnings per limited partner unit:				
Common unit – basic	$ 0.30	$ 0.12	$ 0.16	$ 0.25
Common unit – diluted	$ 0.29	$ 0.12	$ 0.16	$ 0.25
Subordinated unit – basic and diluted	$ 0.30	$ 0.12	$ 0.16	$ 0.25

(1) Retrospectively adjusted for the impact of the Polar and Divide Drop Down, the Red Rock Drop Down and the Bison Drop Down.

The amounts for total revenues as originally filed on the respective 2014 quarterly reports on Form 10-Q have been retrospectively adjusted for the impact of the Polar and Divide Drop Down. There was no impact on net income attributable to partners or EPU. A reconciliation of total revenues follows.

	Quarter ended December 31, 2014	Quarter ended September 30, 2014	Quarter ended June 30, 2014	Quarter ended March 31, 2014
	(In thousands)			
Total revenues as originally reported	$ 94,658	$ 79,030	$ 80,796	$ 76,202
Total revenue impact of Polar and Divide Drop Down	8,328	5,754	5,188	3,179
Total revenues	$ 102,986	$ 84,784	$ 85,984	$ 79,381

The amounts for total revenues as originally filed on the respective 2013 quarterly reports on Form 10-Q have been retrospectively adjusted for the impact of the Polar and Divide Drop Down, the Red Rock Drop Down and Bison Drop Down. There was no impact on net income attributable to partners or EPU. A reconciliation of total revenues follows.

	Quarter ended December 31, 2013	Quarter ended September 30, 2013	Quarter ended June 30, 2013	Quarter ended March 31, 2013
	(In thousands)			
Total revenues as originally reported	$ 69,299	$ 63,096	$ 59,285	$ 43,595
Total revenue impact of Polar and Divide Drop Down	2,143	1,334	386	30
Total revenue impact of Red Rock Drop Down	14,157	12,923	12,176	10,858
Total revenue impact of Bison Drop Down	—	—	—	7,531
Total revenues	$ 85,599	$ 77,353	$ 71,847	$ 62,014