Summit Midstream Partners, LP
Form 10-Q
August 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-35666
Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
x Yes o No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes x No
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	As of July 31, 2015
Common Units	41,972,093 units

Subordinated Units	24,409,850 units
General Partner Units	1,354,700 units

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FORWARD-LOOKING STATEMENTS

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

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

- fluctuations in natural gas, natural gas liquids ("NGLs") and crude oil prices;
- the extent and success of drilling efforts, as well as the extent and quality of natural gas and crude oil volumes produced within proximity of our assets;
- failure or delays by our customers in achieving expected production in their natural gas and crude oil projects;
- competitive conditions in our industry and their impact on our ability to connect hydrocarbon supplies to our gathering and processing assets or systems;
- actions or inactions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers, including the inability or failure of our shipper customers to meet their financial obligations under our gathering agreements;
- our ability to acquire any assets owned by Summit Midstream Partners, LLC ("Summit Investments"), which is subject to a number of factors, including Summit Investments deciding, in its sole discretion, to offer us the right to acquire such assets, the ability to reach agreement on acceptable terms, the approval of the conflicts committee of our general partner's board of directors (if appropriate), prevailing conditions and outlook in the natural gas, NGL and crude oil industries and markets, and our ability to obtain financing on acceptable terms from the credit and/or capital markets or other sources;
- our ability to consummate acquisitions, successfully integrate the acquired businesses, realize any cost savings and other synergies from any acquisition;
- the ability to attract and retain key management personnel;
- commercial bank and capital market conditions and the potential impact of changes or disruptions in the credit and/or capital markets;
- changes in the availability and cost of capital, and the results of our financing efforts, including availability of funds in the credit and/or capital markets;
- restrictions placed on us by the agreements governing our debt instruments;
- the availability, terms and cost of downstream transportation and processing services;
- natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- operational risks and hazards inherent in the gathering, treating and/or 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;

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- 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 document may not in fact occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements.
SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2015	December 31, 2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$26,973	$26,504
Accounts receivable	51,739	89,201
Other current assets	1,648	3,517
Total current assets	80,360	119,222
Property, plant and equipment, net	1,438,798	1,414,350
Intangible assets, net	458,625	477,734
Goodwill	265,062	265,062
Other noncurrent assets	15,908	17,353
Total assets	$2,258,753	$2,293,721
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$13,806	$24,855
Due to affiliate	4,936	2,711
Deferred revenue	677	2,377
Ad valorem taxes payable	6,482	9,118
Accrued interest	17,483	18,858
Other current liabilities	11,068	13,550
Total current liabilities	54,452	71,469
Long-term debt	879,000	808,000
Unfavorable gas gathering contract, net	5,239	5,577
Deferred revenue	62,784	55,239
Other noncurrent liabilities	1,343	1,715
Total liabilities	1,002,818	942,000
Commitments and contingencies		
Common limited partner capital (41,972 units issued and outstanding at June 30, 2015 and 34,427 units issued and outstanding at December 31, 2014)	912,661	649,060
Subordinated limited partner capital (24,410 units issued and outstanding at June 30, 2015 and December 31, 2014)	312,269	293,153
General partner interests (1,355 units issued and outstanding at June 30, 2015 and 1,201 units issued and outstanding at December 31, 2014)	31,005	24,676
Summit Investments' equity in contributed subsidiaries	—	384,832
Total partners' capital	1,255,935	1,351,721
Total liabilities and partners' capital	$2,258,753	$2,293,721

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands, except per-unit amounts)			
Revenues:				
Gathering services and related fees	$61,370	$55,858	$122,137	$105,761
Natural gas, NGLs and condensate sales	11,967	26,703	24,580	53,007
Other revenues	3,937	3,423	7,718	6,597
Total revenues	77,274	85,984	154,435	165,365
Costs and expenses:				
Cost of natural gas and NGLs	4,905	15,118	10,289	29,473
Operation and maintenance	21,616	22,797	42,673	44,628
General and administrative	9,374	9,659	19,032	18,712
Transaction costs	595	76	595	612
Depreciation and amortization	23,978	21,435	47,733	41,814
(Gain) loss on asset sales, net	(214)	6	(214)	6
Total costs and expenses	60,254	69,091	120,108	135,245
Other income	—	1	1	2
Interest expense	(12,083)	(10,803)	(24,201)	(17,947)
Income before income taxes	4,937	6,091	10,127	12,175
Income tax benefit (expense)	105	(469)	(72)	(628)
Net income	$5,042	$5,622	$10,055	$11,547
Less: net income attributable to Summit Investments	2,057	1,586	5,403	3,966
Net income attributable to SMLP	2,985	4,036	4,652	7,581
Less: net income attributable to general partner, including IDRs	1,891	801	3,459	1,232
Net income attributable to limited partners	$1,094	$3,235	$1,193	$6,349
Earnings (loss) per limited partner unit:				
Common unit – basic	$0.05	$0.05	$0.04	$0.14
Common unit – diluted	$0.05	$0.05	$0.04	$0.14
Subordinated unit – basic and diluted	$(0.03)	$0.05	$(0.01)	$0.08
Weighted-average limited partner units outstanding:				
Common units – basic	38,278	34,422	36,369	32,179
Common units – diluted	38,461	34,619	36,477	32,360
Subordinated units – basic and diluted	24,410	24,410	24,410	24,410
Cash distributions declared and paid per common unit	$0.565	$0.500	$1.125	$0.980

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, January 1, 2014	$566,532	$379,287	$23,324	$523,944	$1,493,087
Net income	3,634	2,715	1,232	3,966	11,547
Distributions to unitholders	(31,169)	(23,922)	(1,658)	—	(56,749)
Unit-based compensation	2,424	—	—	—	2,424
Tax withholdings on vested SMLP LTIP awards	(656)	—	—	—	(656)
Issuance of common units, net of offering costs	197,989	—	—	—	197,989
Contribution from general partner	—	—	4,235	—	4,235
Purchase of Red Rock Gathering	—	—	—	(305,000)	(305,000)
Excess of consideration paid over acquired carrying value of Red Rock Gathering	(36,228)	(25,691)	(1,264)	63,183	—
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	22,326	22,326
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	7,423	7,423
Capitalized interest allocated from Summit Investments to contributed subsidiaries	—	—	—	331	331
Capital expenditures paid by Summit Investments to contributed subsidiaries	—	—	—	135	135
Repurchase of SMLP LTIP units	(228)	—	—	—	(228)
Class B membership interest unit-based compensation	—	—	—	170	170
Partners' capital, June 30, 2014	$702,298	$332,389	$25,869	$316,478	$1,377,034

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(continued)

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, January 1, 2015	$649,060	$293,153	$24,676	$384,832	$1,351,721
Net income	715	478	3,459	5,403	10,055
Distributions to unitholders	(38,769)	(27,462)	(4,388)	—	(70,619)
Unit-based compensation	3,049	—	—	—	3,049
Tax withholdings on vested SMLP LTIP awards	(936)	—	—	—	(936)
Issuance of common units, net of offering costs	222,119	—	—	—	222,119
Contribution from general partner	—	—	4,737	—	4,737
Purchase of Polar and Divide	—	—	—	(290,000)	(290,000)
Excess of acquired carrying value over consideration paid for Polar and Divide	77,423	46,100	2,521	(126,044)	—
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	21,719	21,719
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	3,084	3,084
Capitalized interest allocated from Summit Investments to contributed subsidiaries	—	—	—	921	921
Class B membership interest unit-based compensation	—	—	—	85	85
Partners' capital, June 30, 2015	$912,661	$312,269	$31,005	$—	$1,255,935

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30,	
	2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income	$10,055	$11,547
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	48,196	42,265
Amortization of deferred loan costs	1,591	1,220
Unit-based compensation	3,134	2,594
(Gain) loss on asset sales, net	(214)	6
Changes in operating assets and liabilities:		
Accounts receivable	37,463	14,067
Trade accounts payable	(3,849)	2,481
Due to affiliate	5,162	925
Change in deferred revenue	5,845	8,464
Ad valorem taxes payable	(2,635)	(1,259)
Accrued interest	(1,375)	(894)
Other, net	(1,044)	623
Net cash provided by operating activities	102,329	82,039
Cash flows from investing activities:		
Capital expenditures	(60,175)	(88,033)
Proceeds from asset sales	238	24
Acquisitions of gathering systems from affiliate	(292,941)	(305,000)
Net cash used in investing activities	(352,878)	(393,009)

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

	Six months ended June 30,	
	2015	2014
	(In thousands)	
Cash flows from financing activities:		
Distributions to unitholders	(70,619)	(56,749)
Borrowings under revolving credit facility	122,000	160,000
Repayments under revolving credit facility	(51,000)	(20,000)
Deferred loan costs	(86)	(300)
Tax withholdings on vested SMLP LTIP awards	(936)	(656)
Proceeds from issuance of common units, net	222,119	197,989
Contribution from general partner	4,737	4,235
Cash advance from Summit Investments to contributed subsidiaries, net	21,719	22,326
Expenses paid by Summit Investments on behalf of contributed subsidiaries	3,084	7,423
Repurchase of equity-based compensation awards	—	(228)
Net cash provided by financing activities	251,018	314,040
Net change in cash and cash equivalents	469	3,070
Cash and cash equivalents, beginning of period	26,504	20,357
Cash and cash equivalents, end of period	$26,973	$23,427
Supplemental cash flow disclosures:		
Cash interest paid	$24,731	$17,153
Less: capitalized interest	1,651	4,019
Interest paid (net of capitalized interest)	$23,080	$13,134
Noncash investing and financing activities:		
Capital expenditures in trade accounts payable (period-end accruals)	$10,877	$33,115
Excess of acquired carrying value over consideration paid for Polar and Divide	126,044	—
Capitalized interest allocated to contributed subsidiaries from Summit Investments	921	331
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	135
Excess of consideration paid over acquired carrying value of Red Rock Gathering	—	(63,183)

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

Organization. Summit Midstream Partners, LP ("SMLP" or the "Partnership"), a Delaware limited partnership, 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.

SMLP and its subsidiaries are 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 us and has the right to appoint the entire board of directors of our general partner, including our independent directors. Our operations are conducted through, and our operating assets are owned by, various wholly-owned operating subsidiaries. Neither SMLP nor its subsidiaries have any employees. All of the personnel that conduct our business are employed by the general partner and its subsidiaries, but these individuals are sometimes referred to as our employees.

As of June 30, 2015, Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned subsidiary of Summit Investments, 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 incentive distribution rights ("IDRs").

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 in April 2014.

Polar Midstream's assets were carved out of Meadowlark Midstream Company, LLC ("Meadowlark Midstream"), a subsidiary of Summit Investments, 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, LLC ("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.

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:

- the Mountaineer Midstream system ("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;
- the Polar and Divide system ("Polar and Divide"), a crude oil and produced water gathering system and transmission pipelines (under development) located in the Williston Basin;
- DFW Midstream Services LLC ("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, LLC ("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.

Our operating subsidiaries, which are wholly owned by our wholly owned subsidiary, Summit Midstream Holdings, LLC ("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 Company, LLC ("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.

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Presentation and Consolidation. We prepare our unaudited condensed 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 (the "FASB"). The unaudited condensed consolidated financial statements include the assets, liabilities, and results of operations of SMLP and its subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation.

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.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules and the regulations of the Securities and Exchange Commission (the "SEC"). Certain information and note disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information not misleading. In the opinion of management, the unaudited condensed consolidated financial statements contain all adjustments, including normal recurring accruals, which are necessary to fairly present the unaudited condensed consolidated balance sheet as of June 30, 2015, the unaudited condensed consolidated statements of operations for the three- and six-month periods ended June 30, 2015 and 2014, and the unaudited condensed consolidated statements of partners' capital and cash flows for the six-month periods ended June 30, 2015 and 2014. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto that are included in our annual report on Form 10-K for the year ended December 31, 2014 as filed with the SEC on March 2, 2015 (the "2014 Annual Report"). The results of operations for an interim period are not necessarily indicative of results expected for a full year.

SMLP recognized its acquisitions of (i) Polar Midstream and Epping and (ii) Red Rock Gathering (the "Red Rock Drop Down") at Summit Investments' historical cost of construction or fair value of assets and liabilities at acquisition because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment in Polar Midstream and Epping 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 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. For the purposes of these unaudited condensed consolidated financial statements, SMLP's results of operations reflect the results of operations of Polar Midstream, Epping and Red Rock Gathering for all periods presented.

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. In the second quarter of 2015, 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. Also in the second quarter or 2015, we 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 ($1.4 million and $1.3 million for the three months ended June 30, 2015 and 2014, respectively, and $2.7 million and $2.2 million for the six months ended June 30, 2015 and 2014, respectively) from costs of natural gas and NGLs to operation and maintenance.

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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

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

Environmental Matters. We are subject to various federal, state and local laws and regulations relating to the protection of the environment. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties or insurers are recorded as assets when their receipt is deemed probable.

Other Significant Accounting Policies. For information on our other significant accounting policies, see Note 2 of the consolidated financial statements included in the 2014 Annual Report.

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 may 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 July 2015, the FASB reaffirmed the guidance in its April 2015 proposed ASU that 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

As of June 30, 2015, 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.

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Each of our reportable segments provides midstream services in a specific geographic area. Within specific geographic areas, we may further differentiate reportable segments by type of gathering service provided. 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.

In the first quarter of 2015, we combined our Red Rock Gathering operating segment with the Grand River Gathering operating segment to become one operating segment serving the Piceance Basin. Prior to 2015, we aggregated the Red Rock Gathering and Grand River Gathering operating segments into the Piceance Basin reportable segment.

In the second quarter of 2015, 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.

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. Beginning in the first quarter of 2015, we discontinued allocating certain general and administrative expenses, primarily salaries, benefits, incentive compensation and rent expense, to our operating segments.

Assets by reportable segment follow.

	June 30, 2015	December 31, 2014
	(In thousands)	
Assets:		
Marcellus Shale	$239,384	$243,884
Williston Basin – Gas	294,725	311,041
Williston Basin – Liquids	431,951	398,847
Barnett Shale	424,706	428,935
Piceance Basin	833,385	872,437
Total reportable segment assets	2,224,151	2,255,144
Corporate	34,602	38,577
Total assets	$2,258,753	$2,293,721

Revenues by reportable segment follow.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Revenues:				
Marcellus Shale	$7,783	$5,665	$15,622	$11,021
Williston Basin – Gas	7,454	14,819	16,364	31,582
Williston Basin – Liquids	9,906	5,188	18,487	8,367
Barnett Shale	23,823	24,241	47,720	47,277
Piceance Basin	28,308	36,071	56,242	67,118
Total reportable segment revenues and total revenues	$77,274	$85,984	$154,435	$165,365

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Depreciation and amortization by reportable segment follow.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Depreciation and amortization:				
Marcellus Shale	$2,169	$1,861	$4,338	$3,661
Williston Basin – Gas	4,778	4,488	9,476	8,737
Williston Basin – Liquids	1,735	955	3,347	1,692
Barnett Shale	3,902	3,739	7,808	7,376
Piceance Basin	11,210	10,250	22,414	20,063
Total reportable segments	23,794	21,293	47,383	41,529
Corporate	184	142	350	285
Total depreciation and amortization	$23,978	$21,435	$47,733	$41,814

Capital expenditures by reportable segment follow.

	Six months ended June 30,	
	2015	2014
	(In thousands)	
Capital expenditures:		
Marcellus Shale	$637	$10,969
Williston Basin – Gas	8,699	21,884
Williston Basin – Liquids	38,790	24,697
Barnett Shale	1,922	9,856
Piceance Basin	9,734	20,564
Total reportable segments	59,782	87,970
Corporate	393	63
Total capital expenditures	$60,175	$88,033

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 minimum volume commitment ("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.

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

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A reconciliation of income before income taxes to total reportable segment adjusted EBITDA follows.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Reconciliation of Income Before Income Taxes to Segment Adjusted EBITDA:				
Income before income taxes	$4,937	$6,091	$10,127	$12,175
Add:				
Interest expense	12,083	10,803	24,201	17,947
Depreciation and amortization	24,190	21,660	48,196	42,265
Adjustments related to MVC shortfall payments	10,928	10,577	23,268	22,590
Unit-based compensation	1,737	1,446	3,134	2,594
Loss on asset sales	—	6	—	6
Allocated corporate expenses	6,142	2,428	12,000	4,983
Less:				
Interest income	—	1	1	2
Gain on asset sales	214	—	214	—
Total reportable segment adjusted EBITDA	$59,803	$53,010	$120,711	$102,558

Segment adjusted EBITDA by reportable segment follows.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Reportable segment adjusted EBITDA:				
Marcellus Shale	$6,162	$3,837	$12,696	$7,721
Williston Basin – Gas	4,740	4,809	10,075	9,485
Williston Basin – Liquids	6,497	2,626	11,540	3,000
Barnett Shale	15,540	14,958	32,301	29,991
Piceance Basin	26,864	26,780	54,099	52,361
Total reportable segment adjusted EBITDA	$59,803	$53,010	$120,711	$102,558

4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment, net follow.

	Useful lives	June 30,	December 31,
	(In years)	2015	2014
		(Dollars in thousands)	
Gathering and processing systems and related equipment	30	$1,510,375	$1,462,706
Construction in progress	n/a	48,226	44,447
Other	4-15	29,360	28,871
Total		1,587,961	1,536,024
Less accumulated depreciation		149,163	121,674
Property, plant, and equipment, net		$1,438,798	$1,414,350

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Construction in progress is depreciated consistent with its applicable asset class once it is placed in service. Depreciation expense and capitalized interest were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Depreciation expense	$13,851	$12,000	$27,489	$23,197
Capitalized interest	1,003	2,388	1,651	4,019

5. AMORTIZING 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.

	June 30, 2015			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(8,857)	$15,338
Contract intangibles	12.5	426,464	(93,383)	333,081
Rights-of-way	24.3	125,517	(15,311)	110,206
Total intangible assets		$576,176	$(117,551)	$458,625
Unfavorable gas gathering contract	10.0	$10,962	$(5,723)	$5,239

	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 intangible assets		$574,240	$(96,506)	$477,734
Unfavorable gas gathering contract	10.0	$10,962	$(5,385)	$5,577

We recognized amortization expense in other revenues as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Amortization expense – favorable gas gathering contracts	$(375)	$(436)	$(801)	$(870)
Amortization expense – unfavorable gas gathering contract	163	211	338	419

We recognized amortization expense in costs and expenses as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Amortization expense – contract intangibles	$8,835	$8,198	$17,670	$16,160
Amortization expense – rights-of-way	1,293	1,239	2,574	2,457

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The estimated aggregate annual amortization expected to be recognized for the remainder of 2015 and each of the four succeeding fiscal years follows.

	Intangible assets	Unfavorable gas gathering contract
	(In thousands)	
2015	$21,135	$368
2016	42,288	924
2017	41,139	1,047
2018	40,593	1,035
2019	40,838	1,045

6. GOODWILL

We evaluate goodwill for impairment annually on September 30 and whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. There have been no impairments of goodwill during the six months ended June 30, 2015.

Annual Impairment Evaluation. We performed our annual goodwill impairment testing as of September 30, 2014 using a combination of the income and market approaches. Details on the results of the annual goodwill impairment testing for all reporting units except those acquired in the Polar and Divide Drop Down are included in our 2014 Annual Report. 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. We then performed the quantitative analysis for the Polar Midstream reporting unit and determined that the fair value of the Polar Midstream reporting unit substantially exceeded its carrying value, including goodwill as of September 30, 2014. Because the fair value of the Polar Midstream reporting unit exceeded its carrying value, including goodwill, there was no associated impairment of goodwill in connection with our 2014 annual goodwill impairment test and therefore no impairment of the $203.4 million of goodwill that was allocated to the Polar Midstream reporting unit. Because Epping was an organic growth project, it has no goodwill.

Bison Midstream Fourth Quarter 2014 Goodwill Impairment. In the first quarter of 2015, we finalized our calculations of the fair values of the identified assets and liabilities in step two of the December 31, 2014 goodwill impairment testing for the Bison Midstream reporting unit. This process confirmed the preliminary goodwill impairment of $54.2 million that was recognized as of December 31, 2014.

Polar Midstream Fourth Quarter 2014 Goodwill Impairment Evaluation. 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 Midstream reporting unit could have been impaired. Our assessment related to the Polar Midstream reporting unit did result in an indication that the associated goodwill could have been impaired.

We noted that the 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.

In connection therewith, we reperformed our step one analysis as of December 31, 2014. To estimate the fair value of the reporting unit, we utilized two valuation methodologies: the market approach and the income approach. Both of these approaches incorporate significant estimates and assumptions to calculate enterprise fair value for a reporting unit. The most significant estimates and assumptions inherent within these two valuation methodologies are:

- determination of the weighted-average cost of capital;
- the selection of guideline public companies;
- market multiples;
- weighting of the income and market approaches;
- growth rates;

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- 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 and no impairment of goodwill acquired in connection with the Polar and Divide Drop Down.

Our impairment determinations, in the context of (i) our annual impairment evaluation and (ii) our fourth quarter 2014 evaluations, 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.

7. DEFERRED REVENUE

A rollforward of current deferred revenue follows.

	Williston Basin - Gas	Barnett Shale	Piceance Basin	Total current
	(In thousands)			
Current deferred revenue, January 1, 2015	$—	$2,377	$—	$2,377
Additions	—	999	—	999
Less: revenue recognized	—	2,699	—	2,699
Current deferred revenue, June 30, 2015	$—	$677	$—	$677

A rollforward of noncurrent deferred revenue follows.

	Williston Basin - Gas	Barnett Shale	Piceance Basin	Total noncurrent
	(In thousands)			
Noncurrent deferred revenue, January 1, 2015	$17,132	$—	$38,107	$55,239
Additions	—	—	7,572	7,572
Less: revenue recognized	27	—	—	27
Noncurrent deferred revenue, June 30, 2015	$17,105	$—	$45,679	$62,784

As of June 30, 2015, accounts receivable included $3.2 million of shortfall billings related to MVC arrangements that can be utilized to offset gathering fees in subsequent periods. Noncurrent deferred revenue at June 30, 2015 represents amounts that provide certain customers the ability to offset their gathering fees over a period up to six years to the extent that the customer's throughput volumes exceeds its MVC.

8. LONG-TERM DEBT

Long-term debt consisted of the following:

	June 30, 2015	December 31, 2014
	(In thousands)	
Variable rate senior secured revolving credit facility (2.44% at June 30, 2015 and 2.67% at December 31, 2014) due November 2018	$279,000	$208,000
5.50% Senior unsecured notes due August 2022	300,000	300,000
7.50% Senior unsecured notes due July 2021	300,000	300,000
Total long-term debt	$879,000	$808,000

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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 the assets of Summit Holdings and its subsidiaries 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.

As of June 30, 2015, we were in compliance with the revolving credit facility's covenants. There were no defaults or events of default during the six months ended June 30, 2015.

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 (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 their subsidiaries by dividend or loan.

As of June 30, 2015, we were in compliance with the covenants of the 5.5% senior notes and the 7.5% senior notes. There were no defaults or events of default during the six months ended June 30, 2015.

Fair Value of Debt Instruments. A summary of the estimated fair value of our debt financial instruments follows.

	June 30, 2015		December 31, 2014	
	Carrying value	Estimated fair value (Level 2)	Carrying value	Estimated fair value (Level 2)
	(In thousands)			
Revolving credit facility	$279,000	$279,000	$208,000	$208,000
5.5% Senior notes	300,000	286,500	300,000	281,750
7.5% Senior notes	300,000	313,250	300,000	306,750

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 June 30, 2015 and December 31, 2014. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the senior notes.

9. PARTNERS' CAPITAL

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, 2015	34,426,513	24,409,850	1,200,651	60,037,014
Units issued in connection with the May 2015 Equity Offering (1)	7,475,000	—	152,551	7,627,551
Units issued under SMLP LTIP (2)	70,580	—	1,498	72,078
Units, June 30, 2015	41,972,093	24,409,850	1,354,700	67,736,643

(1) Including issuance to general partner in connection with contributions made to maintain 2% general partner interest.

(2) Net of 19,702 units withheld to meet minimum statutory tax withholding requirements

On May 13, 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

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Equity Offering"). On May 22, 2015, the underwriters exercised in full their option to purchase an additional 975,000 common units from us at a price of $30.75 per unit. Concurrent with both transactions, our general partner made a capital contribution to us to maintain its 2% general partner interest.

In June 2015, we concurrently executed an equity distribution agreement and filed a prospectus and a prospectus supplement with the SEC for the issuance and sale from time to time of SMLP common units having an aggregate offering price of up to $150.0 million (the "June 2015 ATM Program"). These sales will be made (i) pursuant to the terms of the equity distribution agreement between us and the sales agents named therein and (ii) by means of ordinary brokers' transactions at market prices, in block transactions or as otherwise agreed between us and the sales agents. Sales of our common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market offerings" as defined by SEC Rules. There were no transactions under the June 2015 ATM Program during the period from inception through June 30, 2015.

Polar and Divide Drop Down. On May 18, 2015, we acquired 100% of the membership interests in Polar Midstream and Epping from a subsidiary of Summit Investments. We paid total cash consideration of $290.0 million in exchange for Summit Investments' $416.0 million net investment in Polar Midstream and Epping (see Note 15 for additional information). We recognized a capital contribution from Summit Investments for the difference between cash consideration paid and Summit Investments' net investment in Polar Midstream and Epping. The calculation of the capital contribution and its allocation to partners' capital follow (dollars in thousands).

Summit Investments' net investment in Polar Midstream and Epping		$416,044
Total cash consideration paid to a subsidiary of Summit Investments		290,000
Excess of acquired carrying value over consideration paid		$126,044
Allocation of capital contribution:		
General partner interest	$2,521	
Common limited partner interest	77,423	
Subordinated limited partner interest	46,100	
Partners' capital contribution – excess of acquired carrying value over consideration paid		$126,044

Red Rock Drop Down. On March 18, 2014, we acquired 100% of the membership interests in Red Rock Gathering from a subsidiary of Summit Investments. We paid total cash consideration of $307.9 million (including working capital adjustments accrued in December 2014 and cash settled in February 2015) in exchange for Summit Investments' net investment in Red Rock Gathering. 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 (dollars 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 consideration paid over acquired carrying value		$(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 distribution – excess of consideration paid over acquired carrying value		$(66,124)

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Details of cash distributions declared in 2015 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, 2014	February 13, 2015	$0.5600	$19,279	$13,670	$702	$1,442	$35,093
March 31, 2015	May 15, 2015	$0.5650	$19,490	$13,792	$710	$1,534	$35,526

On July 22, 2015, the board of directors of our general partner declared a distribution of $0.57 per unit attributable to the quarter ended June 30, 2015. The distribution will be paid on August 14, 2015 to unitholders of record at the close of business on August 7, 2015.

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of Polar and Divide and Red Rock Gathering that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for Polar and Divide and Red Rock Gathering for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. For the three and six months ended June 30, 2015 and 2014, net income was attributed to Summit Investments for (i) Polar and Divide for the period from January 1, 2015 to May 18, 2015 as well as the three and six months ended June 30, 2014 and (ii) Red Rock Gathering for the period from January 1, 2014 to March 18, 2014. Although included in partners' capital, these net income amounts have been excluded from the calculation of earnings per unit ("EPU").

10. EARNINGS PER UNIT

The following table details the components of earnings per limited partner unit.

	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
	(In thousands, except per-unit amounts)			
Numerator for basic and diluted EPU:				
Allocation of net income among limited partner interests:				
Net income attributable to common units	$1,847	$1,891	$1,490	$4,398
Net (loss) income attributable to subordinated units	(753)	1,344	(297)	1,951
Net income attributable to limited partners	$1,094	$3,235	$1,193	$6,349
Denominator for basic and diluted EPU:				
Weighted-average common units outstanding – basic	38,278	34,422	36,369	32,179
Effect of nonvested phantom units	183	197	108	181
Weighted-average common units outstanding – diluted	38,461	34,619	36,477	32,360
Weighted-average subordinated units outstanding – basic and diluted	24,410	24,410	24,410	24,410
Earnings (loss) per limited partner unit:				
Common unit – basic	$0.05	$0.05	$0.04	$0.14
Common unit – diluted	$0.05	$0.05	$0.04	$0.14
Subordinated unit – basic and diluted	$(0.03)	$0.05	$(0.01)	$0.08

We excluded 94,892 units in our calculation of the effect of nonvested phantom units for the six months ended June 30, 2015 because they were anti-dilutive. There were no anti-dilutive units during the three months ended June 30, 2015 or during the three and six months ended June 30, 2014.

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11. 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. In March 2015, we granted 200,283 phantom units to employees in connection with our annual incentive compensation award cycle. These awards had a grant date fair value of $33.94 and vest ratably over a three-year period. As of June 30, 2015, approximately 4.4 million common units remained available for future issuance.

12. 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:

	Three months ended June 30,				Six months ended June 30,			
	2015		2014		2015		2014	
Revenue:								
Counterparty A - Piceance Basin	14	%	17	%	14	%	17	%
Counterparty B - Marcellus Shale	10	%	*		10	%	*	
Counterparty C - Piceance Basin	*		*		*		*	
Counterparty D - Williston Basin – Gas	*		*		*		*	

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* Less than 10%

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

	June 30, 2015		December 31, 2014	
Accounts receivable:				
Counterparty A - Piceance Basin	13	%	27	%
Counterparty B - Marcellus Shale	10	%	*	
Counterparty C - Piceance Basin	11	%	*	
Counterparty D - Williston Basin – Gas	*		13	%

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* Less than 10%

13. RELATED-PARTY 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.

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

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Operation and maintenance expense	$5,586	$5,200	$11,367	$9,570
General and administrative expense	5,534	5,768	11,327	11,640

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 and
- 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.

14. COMMITMENTS AND CONTINGENCIES

Operating Leases. Rent expense related to operating leases, including rent expense incurred on our behalf and allocated to us by Summit Investments, was as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Rent expense	$556	$467	$983	$849

Environmental Matters. There are no material liabilities related to environmental remediation costs, arising from claims, assessments, litigation, fines, or penalties and other sources in the accompanying financial statements at June 30, 2015 or December 31, 2014. However, we can provide no assurance that significant costs and liabilities will not be incurred in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters.

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 AND DROP DOWN TRANSACTIONS

Polar and Divide Drop Down. On May 18, 2015, we acquired Polar Midstream and Epping from a subsidiary of Summit Investments, subject to customary working capital and capital expenditures adjustments. Due to the concurrent timing of acquiring Polar Midstream and Epping, we have aggregated these purchases into the Polar and Divide Drop Down. We funded the initial combined purchase price of $290.0 million with (i) $92.5 million of borrowings under our 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.

Red Rock Drop Down. On March 18, 2014, we 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.

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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 and Red Rock Gathering 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.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
SMLP revenues	$72,583	$80,796	$141,162	$145,685
Polar and Divide revenues	4,691	5,188	13,273	8,367
Red Rock Gathering revenues (1)				11,313
Combined revenues	$77,274	$85,984	$154,435	$165,365
SMLP net income	$2,985	$4,036	$4,652	$7,581
Polar and Divide net income	2,057	1,586	5,403	1,138
Red Rock Gathering net income (1)				2,828
Combined net income	$5,042	$5,622	$10,055	$11,547

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(1) Results are fully reflected in SMLP's revenues and net income subsequent to March 2014.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

This Management’s Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to inform the reader about matters affecting the financial condition and results of operations of SMLP and its subsidiaries for the period since December 31, 2014. As a result, the following discussion should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included in this report and the MD&A and the audited consolidated financial statements and related notes that are included in the 2014 Annual Report. Among other things, those financial statements and the related notes include more detailed information regarding the basis of presentation for the following information. This discussion contains forward-looking statements that constitute our plans, estimates and beliefs. These forward-looking statements involve numerous risks and uncertainties, including, but not limited to, those discussed in Forward-Looking Statements on page ii of this quarterly report on Form 10-Q. Actual results may differ materially from those contained in any forward-looking statements.

MD&A comprises 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

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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 wells 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 the 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 gas gathering agreements are underpinned by areas of mutual interest ("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 3.8 trillion cubic feet equivalent ("Tcfe," determined using a ratio of six Mcf of gas to one barrel ("Bbl") of oil) at June 30, 2015 and average approximately 1.3 Bcfe/d through 2019 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 MVC shortfall. Our MVCs had a weighted-average remaining life of 8.9 years as of June 30, 2015, assuming minimum throughput volumes for the remainder of the term.

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;

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- 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.

In connection with the Polar and Divide Drop Down, our exposure to crude oil supply and demand dynamics has increased. Our expectations regarding any of the above trends 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. For additional information, see the "Trends and Outlook" section of MD&A included in the 2014 Annual Report.

How We Evaluate Our Operations

We conduct and report 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 Gathering.

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.

There have been no changes in these metrics during the six months ended June 30, 2015, except as noted below.

Throughput Volume

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

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

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

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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 the second quarter of 2015, 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.

Subsequent to the reclassification, revenues are recognized as follows:

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

For additional information on our reportable segments and how the other metrics noted above help us manage our business, see Note 3 to the unaudited condensed consolidated financial statements and the "How We Evaluate Our Operations" section of MD&A included in the 2014 Annual Report.

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Results of Operations

Consolidated Overview of the Three and Six Months Ended June 30, 2015 and 2014

The following table presents certain consolidated and other financial and operating data as of or for the periods indicated.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(Dollars in thousands, except fee-rate data)			
Revenues:				
Gathering services and related fees	$61,370	$55,858	$122,137	$105,761
Natural gas, NGLs and condensate sales	11,967	26,703	24,580	53,007
Other revenues	3,937	3,423	7,718	6,597
Total revenues	77,274	85,984	154,435	165,365
Costs and expenses:				
Cost of natural gas and NGLs	4,905	15,118	10,289	29,473
Operation and maintenance	21,616	22,797	42,673	44,628
General and administrative	9,374	9,659	19,032	18,712
Transaction costs	595	76	595	612
Depreciation and amortization	23,978	21,435	47,733	41,814
(Gain) loss on asset sales, net	(214)	6	(214)	6
Total costs and expenses	60,254	69,091	120,108	135,245
Other income	—	1	1	2
Interest expense	(12,083)	(10,803)	(24,201)	(17,947)
Income before income taxes	4,937	6,091	10,127	12,175
Income tax benefit (expense)	105	(469)	(72)	(628)
Net income	$5,042	$5,622	$10,055	$11,547
Other Financial Data:				
EBITDA (1)	$41,210	$38,553	$82,523	$72,385
Adjusted EBITDA (1)	53,661	50,582	108,711	97,575
Capital expenditures (2)	34,987	34,453	60,175	88,033
Acquisitions of gathering systems (3)	290,000	—	292,941	305,000
Distributable cash flow (1)(2)	39,762	37,295	80,688	70,897
Operating Data:				
Miles of pipeline as of June 30	2,658	2,568	2,658	2,568
Aggregate average throughput – gas (MMcf/d)	1,519	1,403	1,552	1,356
Aggregate average throughput rate per Mcf – gas	$0.41	$0.43	$0.40	$0.43
Average throughput – liquids (Mbbl/d)	54.3	30.1	51.2	26.9
Average throughput rate per Bbl – liquids	$1.79	$1.72	$1.79	$1.54

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(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 purchase price and working capital adjustments) and value of units issued, if any, to fund acquisitions and/or drop downs. For additional information, see Note 15 to the unaudited condensed consolidated financial statements.

Volumes – Gas. For the three months ended June 30, 2015, our aggregate natural gas throughput volumes increased to an average of 1,519 MMcf/d, compared with an average of 1,403 MMcf/d in the prior-year period. The

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increase in natural gas volume throughput largely reflects the contribution from Mountaineer Midstream, partially offset by volume throughput declines at Grand River Gathering.

For the six months ended June 30, 2015, our aggregate natural gas throughput volumes increased to an average of 1,552 MMcf/d, compared with an average of 1,356 MMcf/d for the six months ended June 30, 2014. The increase in volume throughput largely reflects the contribution from Mountaineer Midstream and DFW Midstream, partially offset by volume throughput declines on Grand River Gathering.

Volumes – Liquids. Average daily throughput for crude oil and produced water increased to 54.3 Mbbl/d for the three months ended June 30, 2015, compared with an average of 30.1 Mbbl/d in the prior-year period. For the six months ended June 30, 2015, average daily throughput for crude oil and produced water increased to 51.2 Mbbl/d, compared with an average of 26.9 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 three months ended June 30, 2015, total revenues decreased $8.7 million, or 10%. For the six months ended June 30, 2015, total revenues decreased $10.9 million, or 7%. The decrease in total revenues in each period reflects a decline in natural gas, NGLs and condensate sales for Bison Midstream, Grand River Gathering and DFW Midstream, partially offset by an increase in gathering services and related fees across all gathering systems, except Grand River Gathering.

Gathering Services and Related Fees. The increase in gathering services and related fees during the three months ended June 30, 2015 was primarily driven by higher volume throughput on the Polar and Divide and Mountaineer Midstream systems, partially offset by lower volumes at Grand River Gathering. The aggregate average throughput rate for natural gas decreased to $0.41/Mcf during the three months ended June 30, 2015, compared with $0.43/Mcf in the prior-year period primarily as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream. The aggregate average throughput rate for crude oil and produced water increased to $1.79/Bbl during the three months ended June 30, 2015, compared with $1.72/Bbl in the prior-year period 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.

The increase in gathering services and related fees during the six months ended June 30, 2015 was primarily driven by higher volume throughput on the Polar and Divide, Mountaineer Midstream and DFW Midstream systems. The aggregate average throughput rate decreased to $0.40/Mcf during the six months ended June 30, 2015, compared with $0.43/Mcf in the prior-year period primarily as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream. The aggregate average throughput rate for crude oil and produced water increased to $1.79/Bbl during the six months ended June 30, 2015, compared with $1.54/Bbl in the prior-year period primarily as a result of the effect of contract amendments noted above.

Natural Gas, NGLs and Condensate Sales. The decrease in natural gas, NGLs and condensate sales for the three and six months ended June 30, 2015 was primarily a result of the impact of declining commodity prices, partially offset by an increase in volumes on the Bison Midstream and Grand River Gathering systems that are subject to percent-of-proceeds arrangements. Declining commodity prices negatively impacted our percent-of-proceeds arrangements at Bison Midstream and Grand River Gathering, our fuel retainage revenue at DFW Midstream and condensate revenue for Grand River Gathering.

Costs and Expenses. Total costs and expenses decreased $8.8 million, or 13%, for the three months ended June 30, 2015, and $15.1 million, or 11%, for the six months ended June 30, 2015 primarily due to a decrease in cost of natural gas and NGLs at Bison Midstream and Grand River Gathering and a decrease in operation and maintenance across our gathering systems, except for Polar and Divide. These decreases were partially offset by an increase in depreciation and amortization across our gathering systems.

Cost of Natural Gas and NGLs. The decrease in cost of natural gas and NGLs during the three and six months ended June 30, 2015 was largely driven by declining commodity prices and the associated impact on our percent-of-proceeds arrangements at Bison Midstream and Grand River Gathering. This impact was partially offset by an increase in volume throughput for these arrangements.

Operation and Maintenance. Operation and maintenance expense decreased during the three and six months ended June 30, 2015 primarily reflecting a decline in electricity expense associated with running compressors on the DFW Midstream system, a decline in pass-through electricity expense for Grand River Gathering (revenue component is recognized in other revenues), and a decline in contract services for Bison Midstream. These decreases were partially offset by an increase in connection fee pass-through expense for Polar and Divide as a result of system expansion (revenue component is recognized in other revenues) as well as an increase in

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operation and maintenance for Mountaineer Midstream primarily as a result of system expansion and the associated increase in volume throughput.

General and Administrative. General and administrative expense decreased during the three and six months ended June 30, 2015 primarily reflecting a decline in professional services expense that was partially offset by an increase in rent and technology expenses.

Transaction Costs. Transaction costs recognized during the three and six months ended June 30, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down. Transaction costs recognized during the six months ended June 30, 2014 primarily related to financial and legal advisory costs associated with the Red Rock Drop Down.

Depreciation and Amortization. The increase in depreciation and amortization expense during the three and six months ended June 30, 2015 was largely driven by an increase in assets placed into service and contract amortization, with the substantial majority of the increase being attributed to Grand River Gathering and Polar and Divide.

Interest Expense. The increase in interest expense during the three and six months ended June 30, 2015, was primarily driven by our issuance of $300.0 million of 5.5% senior notes in July 2014.

For additional information on how our financial results are recognized, see the "Results of Operations" section of MD&A included in the 2014 Annual Report.

Segment Overview of the Three and Six Months Ended June 30, 2015 and 2014

Marcellus Shale. Mountaineer Midstream provides our midstream services for the Marcellus Shale reportable segment. Volume throughput averaged:

- 542 MMcf/d for the three months ended June 30, 2015, compared with 366 MMcf/d in the prior-year period and
- 545 MMcf/d for the six months ended June 30, 2015, compared with 326 MMcf/d in the prior-year period.

Volume growth was primarily driven by the upstream connection of wells owned by Mountaineer Midstream's anchor customer.

Information regarding our Marcellus Shale reportable segment follows.

	Marcellus Shale (1)							
	Three months ended June 30,		Percentage		Six months ended June 30,		Percentage	
	2015	2014	Change		2015	2014	Change	
	(Dollars in thousands)							
Revenues:								
Gathering services and related fees	$7,783	$5,665	37	%	$15,622	$11,021	42	%
Total revenues	7,783	5,665	37	%	15,622	11,021	42	%
Costs and expenses:								
Operation and maintenance	1,520	1,255	21	%	2,735	2,224	23	%
General and administrative	101	573	*		191	1,076	*	
Depreciation and amortization	2,169	1,861	17	%	4,338	3,661	18	%
Total costs and expenses	3,790	3,689	3	%	7,264	6,961	4	%
Add:								
Depreciation and amortization	2,169	1,861			4,338	3,661		
Segment adjusted EBITDA	$6,162	$3,837	61	%	$12,696	$7,721	64	%
Average throughput (MMcf/d)	542	366	48	%	545	326	67	%

* Not considered meaningful

(1) Contract terms related to throughput rate per MCF are excluded for confidentiality purposes.

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Three and six months ended June 30, 2015. Segment adjusted EBITDA increased $2.3 million during the three months ended June 30, 2015 and $5.0 million during the six months ended June 30, 2015 reflecting:

- the impact of an increase in volume throughput which translated into higher gathering services and related fees revenue.
- the benefit of higher volume throughput was partially offset by a decline in compression services, which resulted from a shift in volume throughput mix to a larger percentage of previously compressed natural gas entering our gathering lines. As a result of this shift in volume throughput mix, the proportion of high-pressure gathering services increased, which, due to its lower rate relative to compression fees, negatively impacted gathering services and related fees as well as the average throughput rate per Mcf.
- minimum revenue commitment payments related to the recently completed Zinnia Loop project, beginning in the first quarter of 2015.
- an increase in operation and maintenance primarily as a result of system expansion and the associated increase in volume throughput.
- a decline in general and administrative expenses primarily as a result of our decision to discontinue allocating certain corporate general and administrative expenses beginning in the first quarter of 2015.

Depreciation and amortization increased during the three and six months ended June 30, 2015 largely as a result of assets placed into service during the third quarter of 2014, most notably the Zinnia Loop project.

Williston Basin – Gas. Bison Midstream provides our midstream services for the Williston Basin – Gas reportable segment. Volume throughput averaged:

- 17 MMcf/d for the three months ended June 30, 2015, compared with 15 MMcf/d in the prior-year period and
- 18 MMcf/d for the six months ended June 30, 2015, compared with 14 MMcf/d in the prior-year period.

The increase in volume throughput in 2015 primarily reflects additional pad site connections and compression capacity installed in the latter half of 2014, which improved system hydraulics. This benefit was partially offset by the impact of a customer's decision to shut-in their wells late in the first quarter of 2015. Volume throughput for the six months ended June 30, 2014 also reflected the impact of severe winter weather in northwestern North Dakota and operational challenges caused by water hydrate issues both in the first quarter of 2014. These issues were remediated during the second quarter of 2014.

Bison Midstream's average throughput rate was:

- $2.48/Mcf during the three months ended June 30, 2015, compared with $3.71/Mcf in the prior-year period and
- $2.64/Mcf during the six months ended June 30, 2015, compared with $4.09/Mcf in the prior-year period.

These declines were primarily a result of a larger proportion of volumes associated with percent-of-proceeds contracts and the impact of declining commodity prices.

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Information regarding our Williston Basin – Gas reportable segment follows.

	Williston Basin – Gas					
	Three months ended June 30,		Percentage Change	Six months ended June 30,		Percentage Change
	2015	2014		2015	2014	
	(Dollars in thousands, except fee-rate data)					
Revenues:						
Gathering services and related fees	$239	$222	8 %	$483	$431	12 %
Natural gas, NGLs and condensate sales	5,890	13,327	(56)%	13,249	28,803	(54)%
Other revenues	1,325	1,270	4 %	2,632	2,348	12 %
Total revenues	7,454	14,819	(50)%	16,364	31,582	(48)%
Costs and expenses:						
Cost of natural gas and NGLs	2,163	8,353	(74)%	5,242	19,144	(73)%
Operation and maintenance	3,234	3,474	(7)%	6,223	6,434	(3)%
General and administrative	157	816	*	324	1,844	*
Depreciation and amortization	4,778	4,488	6 %	9,476	8,737	8 %
Loss on asset sales	—	6	(100)%	—	6	(100)%
Total costs and expenses	10,332	17,137	(40)%	21,265	36,165	(41)%
Add:						
Depreciation and amortization	4,778	4,488		9,476	8,737	
Adjustments related to MVC shortfall payments	2,840	2,633		5,500	5,325	
Loss on asset sales	—	6		—	6	
Segment adjusted EBITDA	$4,740	$4,809	(1)%	$10,075	$9,485	6 %
Average throughput (MMcf/d)	17	15	13 %	18	14	29 %
Average throughput rate per Mcf	$2.48	$3.71	(33)%	$2.64	$4.09	(35)%

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* Not considered meaningful

Three and six months ended June 30, 2015. Segment adjusted EBITDA decreased $0.1 million for the three months ended June 30, 2015 and increased $0.6 million during the six months ended June 30, 2015 reflecting:

- the impact of declining commodity prices which negatively affected the margins we earn under percent-of-proceeds arrangements.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- a decrease in operation and maintenance expenses reflecting the impact of a decline in contract services and the first quarter 2014 water hydrate remediation effort.

Depreciation and amortization increased during the three and six months ended June 30, 2015 largely as a result of compression assets placed into service during the second half of 2014.

Williston Basin – Liquids. Polar and Divide provides our midstream services for the Williston Basin – Liquids reportable segment. Volume throughput averaged:

- 54.3 Bbl/d for the three months ended June 30, 2015, compared with 30.1 Bbl/d in the prior-year period and
- 51.2 Bbl/d for the six months ended June 30, 2015, compared with 26.9 Bbl/d in the prior-year period.

The increase in volume throughput in 2015 reflects new pad site connections and ongoing drilling activity in Polar and Divide's service area.

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Polar and Divide's average throughput rate was:
- $1.79/Bbl during the three months ended June 30, 2015, compared with $1.72/Bbl in the prior-year period and
- $1.79/Bbl during the six months ended June 30, 2015, compared with $1.54/Bbl in the prior-year period.

The increase in average throughput rate was 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.
Information regarding our Williston Basin – Liquids reportable segment follows.

	Williston Basin – Liquids							
	Three months ended June 30,		Percentage		Six months ended June 30,		Percentage	
	2015	2014	Change		2015	2014	Change	
	(Dollars in thousands, except fee-rate data)							
Revenues:								
Gathering services and related fees	$8,826	$4,699	88	%	$16,551	$7,471	122	%
Other revenues	1,080	489	121	%	1,936	896	116	%
Total revenues	9,906	5,188	91	%	18,487	8,367	121	%
Costs and expenses:								
Operation and maintenance	2,579	1,664	55	%	4,896	3,387	45	%
General and administrative	830	983	*		2,136	2,150	*	
Depreciation and amortization	1,735	955	82	%	3,347	1,692	98	%
Total costs and expenses	5,144	3,602	43	%	10,379	7,229	44	%
Add:								
Depreciation and amortization	1,735	955			3,347	1,692		
Unit-based compensation	—	85			85	170		
Segment adjusted EBITDA	$6,497	$2,626	147	%	$11,540	$3,000	285	%
Average throughput (Mbbl/d)	54.3	30.1	80	%	51.2	26.9	90	%
Average throughput rate per Bbl	$1.79	$1.72	4	%	$1.79	$1.54	16	%

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* Not considered meaningful

Three and six months ended June 30, 2015. Segment adjusted EBITDA increased $3.9 million during the three months ended June 30, 2015 and $8.5 million during the six months ended June 30, 2015 reflecting:
- the impact of higher volume throughput on gathering services and related fees.
- higher gathering rates associated with contract amendments in 2014.
- an increase in operation and maintenance expenses largely as a result of system buildout.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.

Other revenues and operation and maintenance also reflect the effect of an increase in connection fees, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased during the three and six months ended June 30, 2015 largely as a result of gathering pipeline placed into service during 2014.

Barnett Shale. DFW Midstream provides our midstream services for the Barnett Shale reportable segment. Volume throughput averaged:
- 356 MMcf/d during the three months ended June 30, 2015, compared with 350 MMcf/d in the prior-year period and

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- 379 MMcf/d during the six months ended June 30, 2015, compared with 349 MMcf/d in the prior-year period.

Volume throughput was flat during the second quarter of 2015 primarily reflecting the contribution of the Lonestar assets (acquired September 30, 2014), partially offset by drilling and completion activities from several customers which restrained production and a lack of drilling activity by DFW Midstream's anchor customer. The increase in volume throughput for the year-to-date period primarily reflects first quarter 2015 customer production which recommenced from several pad sites that had been temporarily shut-in for drilling and completion activities beginning in the third quarter of 2013 and continuing until late 2014 as well as the contribution of the Lonestar assets. These increases were partially offset by the impact of the second quarter 2015 drilling and completion activities noted above, including the lack of drilling by DFW Midstream's anchor customer.

DFW Midstream's average throughput rate was:

- $0.67/Mcf during the three months ended June 30, 2015, compared with $0.62/Mcf in the prior-year period and
- $0.63/Mcf during the six months ended June 30, 2015, compared with $0.60/Mcf in the prior-year period.

The increase in average throughput rate for the three and six months ended June 30, 2015 is primarily the result of increased volumes from customers with higher gathering rates.

Information regarding our Barnett Shale reportable segment follows.

	Barnett Shale Three months ended June 30,		Percentage Change		Six months ended June 30,		Percentage Change	
	2015	2014			2015	2014		
	(Dollars in thousands, except fee-rate data)							
Revenues:								
Gathering services and related fees	$21,879	$20,561	6	%	$43,675	$39,737	10	%
Natural gas, NGLs and condensate sales	1,699	3,869	(56	)%	3,620	7,933	(54	)%
Other revenues	245	(189)	*		425	(393)	*	
Total revenues	23,823	24,241	(2	)%	47,720	47,277	1	%
Costs and expenses:								
Operation and maintenance	6,336	7,640	(17	)%	13,148	15,532	(15	)%
General and administrative	381	1,193	*		733	2,363	*	
Depreciation and amortization	3,902	3,739	4	%	7,808	7,376	6	%
Total costs and expenses	10,619	12,572	(16	)%	21,689	25,271	(14	)%
Add:								
Depreciation and amortization	4,114	3,964			8,271	7,827		
Adjustments related to MVC shortfall payments	(1,778)	(675)			(2,001)	158		
Segment adjusted EBITDA	$15,540	$14,958	4	%	$32,301	$29,991	8	%
Average throughput (MMcf/d)	356	350	2	%	379	349	9	%
Average throughput rate per Mcf	$0.67	$0.62	8	%	$0.63	$0.60	5	%

*Not considered meaningful

Three and six months ended June 30, 2015. Segment adjusted EBITDA increased $0.6 million during the three months ended June 30, 2015 and $2.3 million during the six months ended June 30, 2015 reflecting:

- the impact of declining natural gas prices on the fuel retainage fee that is paid in-kind by certain of our customers to offset the costs we incur to operate DFW Midstream's electric-drive compression assets.

- for the three-month period, an increase in gathering services and related fees due to increased rates.

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- for the six-month period, an increase in gathering services and related fees due to increased rates and higher volumes in the first quarter of 2015.
- a decline in operation and maintenance expense primarily due to lower electricity expense. We purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices. As a result, the decline in natural gas prices translated into lower electricity expenses.
- a decline in third-party natural gas treating expenses for the six-month period, which we recognize in operation and maintenance. In February 2014, we commissioned a new 150 gallon per minute natural gas treating facility which allowed us to provide treating services to our customers rather than having to contract with a third-party service provider for such services.
- adjustments due to the expiration of deferred revenue credits in April 2015.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.

Depreciation and amortization increased during the three and six months ended June 30, 2015 largely as a result of placing the Lonestar assets into service in September 2014.

Piceance Basin. Grand River Gathering provides our midstream services for the Piceance Basin reportable segment. Red Rock Gathering became part of the Grand River Gathering system in connection with the Red Rock Drop Down in March 2014. Our results include activity for Red Rock Gathering for all periods presented.

Volume throughput averaged:

- 604 MMcf/d during the three months ended June 30, 2015, compared with 672 MMcf/d during the prior-year period and
- 610 MMcf/d during the six months ended June 30, 2015, compared with 667 MMcf/d during the prior-year period.

The declines in volume were primarily a result of Encana's temporary suspension of drilling activities, which began in the fourth quarter of 2013. This decline was partially offset by new pad site connections, and, for the six-month period, the March 2014 start-up of a cryogenic processing plant.

The average throughput rate was:

- $0.41/Mcf during the three months ended June 30, 2015, compared with $0.40/Mcf during the prior-year period and
- $0.42/Mcf during the six months ended June 30, 2015, compared with $0.39/Mcf during prior-year period.

The change in average throughput rates for the three- and six-month periods largely reflect a shift in volume mix. Certain of our gas gathering agreements for Grand River Gathering include MVCs that 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.

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Information regarding our Piceance Basin reportable segment follows.

	Piceance Basin					
	Three months ended June 30,		Percentage Change	Six months ended June 30,		Percentage Change
	2015	2014		2015	2014	
	(Dollars in thousands, except fee-rate data)					
Revenues:						
Gathering services and related fees	$22,643	$24,711	(8)%	$45,806	$47,101	(3)%
Natural gas, NGLs and condensate sales	4,378	9,507	(54)%	7,711	16,271	(53)%
Other revenues	1,287	1,853	(31)%	2,725	3,746	(27)%
Total revenues	28,308	36,071	(22)%	56,242	67,118	(16)%
Costs and expenses:						
Cost of natural gas and NGLs	2,742	6,765	(59)%	5,047	10,329	(51)%
Operation and maintenance	7,947	8,764	(9)%	15,671	17,051	(8)%
General and administrative	621	2,381	*	1,194	4,484	*
Depreciation and amortization	11,210	10,250	9 %	22,414	20,063	12 %
Gain on asset sales	(214)	—	100 %	(214)	—	100 %
Total costs and expenses	22,306	28,160	(21)%	44,112	51,927	(15)%
Add:						
Depreciation and amortization	11,210	10,250		22,414	20,063	
Adjustments related to MVC shortfall payments	9,866	8,619		19,769	17,107	
Less gain on asset sales	214	—		214	—	
Segment adjusted EBITDA	$26,864	$26,780	0 %	$54,099	$52,361	3 %
Average throughput (MMcf/d)	604	672	(10)%	610	667	(9)%
Average throughput rate per Mcf	$0.41	$0.40	3 %	$0.42	$0.39	8 %

* Not considered meaningful

Three months ended June 30, 2015. Segment adjusted EBITDA for the three months ended June 30, 2015 was flat reflecting:

- lower gathering services revenue from our anchor customer.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- an increase in anticipated MVC shortfall payments due to increasing rate and volume commitment provisions in certain gas gathering agreements.
- the impact of declining commodity prices which negatively impacted the margins that we earn from our percent-of-proceeds contracts and the condensate drip that we retain.
- a decline in operation and maintenance due to lower property taxes, partially offset by an increase in compressor parts.

Other revenues and operation and maintenance also reflect the effect of a decrease in certain electricity expenses, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased $1.0 million during the three months ended June 30, 2015 largely as a result of an increase in contract amortization for Grand River Gathering's anchor customer.

Six months ended June 30, 2015. Segment adjusted EBITDA for the six months ended June 30, 2015 increased $1.7 million reflecting:

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- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- the impact of declining commodity prices which negatively impacted the margins that we earn from our percent-of-proceeds contracts.
- an increase in anticipated MVC shortfall payments due to increasing rate and volume commitment provisions in certain gas gathering agreements.
- a decline in operation and maintenance due to lower property taxes.
- lower gathering services revenue from our anchor customer.

Other revenues and operation and maintenance also reflect the effect of a decrease in certain electricity expenses, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased $2.4 million during the six months ended June 30, 2015 largely as a result of an increase in contract amortization for Grand River Gathering's anchor customer and the March 2014 commissioning of a cryogenic processing plant.

Corporate. Corporate represents those revenues and expenses that are not specifically attributable to a reportable segment or that have not been allocated to our reportable segments, including certain general and administrative expense items, transaction costs and interest expense. Items to note follow.

	Corporate Three months ended June 30,		Percentage Change	Six months ended June 30,		Percentage Change
	2015	2014		2015	2014	
	(In thousands)					
Costs and expenses:						
General and administrative	$7,284	$3,713	96 %	$14,454	$6,795	113 %
Transaction costs	595	76	*	595	612	(3)%
Depreciation and amortization	184	142	30 %	350	285	23 %
Interest expense	12,083	10,803	12 %	24,201	17,947	35 %

*Not considered meaningful

General and Administrative. The increase in general and administrative expense during the three and six months ended June 30, 2015, largely reflects the impact of our decision to discontinue allocating certain expenses, primarily salaries, benefits, incentive compensation and rent expense, to our operating segments.

Transaction Costs. Transaction costs recognized during the three and six months ended June 30, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down.

Transaction costs recognized during the six months ended June 30, 2014 primarily relate to financial and legal advisory costs associated with the Red Rock Drop Down.

Interest Expense. The increase in interest expense during the three and six months ended June 30, 2015, was primarily driven by our July 2014 issuance of the 5.5% senior notes.

Non-GAAP Financial Measures

EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We define EBITDA as net income, 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.

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Net income 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. For additional information on the limitations of our non-GAAP financial measures and how we compensate for those limitations, see the "Non-GAAP Financial Measures" section of MD&A included in the 2014 Annual Report.

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 unaudited condensed 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.
- 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 consolidated financial statements included in the 2014 Annual Report.
- 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.
- 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 unaudited condensed consolidated financial statements and Note 15 to the consolidated financial statements included in the 2014 Annual Report.
- 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.

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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.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Reconciliation of net income to EBITDA, adjusted EBITDA and distributable cash flow:				
Net income	$5,042	$5,622	$10,055	$11,547
Add:				
Interest expense	12,083	10,803	24,201	17,947
Income tax expense	—	469	72	628
Depreciation and amortization	24,190	21,660	48,196	42,265
Less:				
Interest income	—	1	1	2
Income tax benefit	105	—	—	—
EBITDA	$41,210	$38,553	$82,523	$72,385
Add:				
Adjustments related to MVC shortfall payments	10,928	10,577	23,268	22,590
Unit-based compensation	1,737	1,446	3,134	2,594
Loss on asset sales	—	6	—	6
Less gain on asset sales	214	—	214	—
Adjusted EBITDA	$53,661	$50,582	$108,711	$97,575
Add cash interest received	—	1	1	2
Less:				
Cash interest paid	1,919	2,845	24,731	17,153
Senior notes interest	9,750	5,625	(1,421)	(875)
Maintenance capital expenditures	2,230	4,818	4,714	10,402
Distributable cash flow	$39,762	$37,295	$80,688	$70,897

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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.

	Six months ended June 30,	
	2015	2014
	(In thousands)	
Reconciliation of net cash provided by operating activities to EBITDA, adjusted EBITDA and distributable cash flow:		
Net cash provided by operating activities	$102,329	$82,039
Add:		
Interest expense	22,610	16,727
Income tax expense	72	628
Changes in operating assets and liabilities	(39,567)	(24,407)
Gain on asset sales	214	—
Less:		
Unit-based compensation	3,134	2,594
Interest income	1	2
Loss on asset sales	—	6
EBITDA	$82,523	$72,385
Add:		
Adjustments related to MVC shortfall payments	23,268	22,590
Unit-based compensation	3,134	2,594
Loss on asset sales	—	6
Less gain on asset sales	214	—
Adjusted EBITDA	$108,711	$97,575
Add cash interest received	1	2
Less:		
Cash interest paid	24,731	17,153
Senior notes interest	(1,421)	(875)
Maintenance capital expenditures	4,714	10,402
Distributable cash flow	$80,688	$70,897

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.

Capital Markets Activity

We had no capital markets activity during the six months ended June 30, 2015, except as noted below.

November 2013 Shelf Registration Statement. On May 13, 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"). On May 22, 2015, the underwriters exercised in full their option to purchase an additional 975,000 common units from us at a price of $30.75 per unit. Concurrent with both transactions, our general partner made a capital contribution to us to maintain its 2% general partner interest. We used the proceeds from the May 13, 2015 transaction to partially fund the Polar and Divide Drop Down. We used $25.0 million of the $29.0 million proceeds from the exercise of the underwriters' option to pay down our revolving credit facility. Following the May 2015 Equity Offering and the exercise of the underwriters' option, we can issue up to $464.8 million of debt and equity securities in primary offerings and 5,293,571 common units pursuant to this shelf registration statement.

In June 2015, we executed an equity distribution agreement and filed a prospectus and a prospectus supplement with the SEC for the issuance and sale from time to time of SMLP common units having an aggregate offering price of up to $150.0 million. These sales will be made (i) pursuant to the terms of the equity distribution agreement between us and the sales agents named therein and (ii) by means of ordinary brokers' transactions at market prices, in block transactions or as otherwise agreed between us and the sales agents. Sales of our common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market offerings" as defined by SEC Rules. There were no transactions under the June 2015 ATM Program during the period from inception through June 30, 2015.

For additional information, see the "Liquidity and Capital Resources—Capital Markets Activity" section of MD&A included in the 2014 Annual Report.

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 the assets of Summit Holdings and its subsidiaries 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. As of June 30, 2015, the outstanding balance of the revolving credit facility was $279.0 million and the unused portion totaled $421.0 million. As of June 30, 2015, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during the six months ended June 30, 2015.

Senior Notes. In July 2014, Summit Holdings and Summit Midstream Finance Corp. co-issued $300.0 million of 5.50% senior unsecured notes maturing August 15, 2022. In June 2013, they co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021. There were no defaults or events of default during the six months ended June 30, 2015 on either series of senior notes.

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

Cash Flows

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

	Six months ended June 30,	
	2015	2014
	(In thousands)	
Net cash provided by operating activities	$102,329	$82,039
Net cash used in investing activities	(352,878)	(393,009)
Net cash provided by financing activities	251,018	314,040
Net change in cash and cash equivalents	$469	$3,070

Operating activities. Cash flows from operating activities increased by $20.3 million for the six months ended June 30, 2015 primarily due to cash received as a result of MVCs. These cash receipts were largely offset by an increase in interest due to the 5.5% senior notes and other operating activities.

Investing activities. Cash flows used in investing activities for the six months ended June 30, 2015 were related primarily to the Polar and Divide Drop Down as well as the ongoing expansion of compression capacity on the Bison Midstream system and pipeline construction projects to connect new receipt points on the Grand River and Bison Midstream systems and the settlement of the working capital adjustment associated with the Red Rock Drop Down. Cash flows used in investing activities for the six months ended June 30, 2014 primarily reflect the Partnership's acquisition of Red Rock Gathering from an affiliate of Summit Investments. Additional expenditures in the six months ended June 30, 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, and commissioning a new natural gas treating facility on the DFW Midstream system in February 2014.

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Financing activities. Details of cash flows provided by financing activities were as follows:
Net cash used in financing activities for the six months ended June 30, 2015 was primarily composed of the following:

- Net proceeds from an offering of common units in May 2015, which were used to partially fund the Polar and Divide Drop Down;
- Net borrowings under our revolving credit facility, including $92.5 million to partially fund the Polar and Divide Drop Down; and
- Distributions declared in respect of both the first quarter of 2015 (paid in the second quarter of 2015) and fourth quarter of 2014 (paid in the first quarter of 2015).

Net cash provided by financing activities for the six months ended June 30, 2014 was primarily composed of the following:

- Net proceeds from an offering of common units in March 2014, which were used to partially fund the Red Rock Drop Down;
- Net borrowings of $140.0 million under our revolving credit facility, including $100.0 million to partially fund the Red Rock Drop Down; and
- Distributions declared in respect of the first quarter of 2014 (paid in the second quarter of 2014) and fourth quarter of 2013 (paid in the first quarter of 2014).

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.

For the six months ended June 30, 2015, SMLP recorded total capital expenditures of $60.2 million, which included $4.7 million of maintenance capital expenditures.

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 $421.0 million of available capacity at June 30, 2015, 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 Note 9 to the unaudited condensed 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 12 to the unaudited condensed consolidated financial statements.

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Off-Balance Sheet Arrangements
We had no off-balance sheet arrangements as of or during the six months ended June 30, 2015.

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

There have been no changes in the accounting methodology for items that we have identified as critical accounting estimates during the six months ended June 30, 2015.

Goodwill. As of December 31, 2014, 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. In the first quarter of 2015, we finalized our calculations of the fair values of the identified assets and liabilities, confirming the preliminary goodwill impairment of $54.2 million. For additional information, see Note 6 to the unaudited condensed consolidated financial statements and Note 5 to the consolidated financial statements included in the 2014 Annual Report.

For additional information regarding critical accounting estimates generally, see the "Critical Accounting Estimates" section of MD&A included in the 2014 Annual Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.
Interest Rate Risk
We have exposure to changes in interest rates on our indebtedness associated with the revolving credit facility. Our current interest rate risk exposure has not changed materially since December 31, 2014. See the "Interest Rate Risk" section included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk of the 2014 Annual Report for additional information.

Commodity Price Risk
We currently generate a substantial majority of our revenues pursuant to primarily long-term and fee-based gathering and processing agreements, many of which include MVCs and areas of mutual interest. Our direct commodity price exposure relates to (i) our sale of physical natural gas we retain from our DFW Midstream customers, (ii) our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system, (iii) the sale of condensate volumes that we retain on the Grand River Gathering system and (iv) the sale of processed natural gas and natural gas liquids pursuant to our percent-of-proceeds and keep-whole contracts with certain of our customers on the Bison Midstream and Grand River Gathering systems. Our current commodity price risk exposure has not changed materially since December 31, 2014. See the "Commodity Price Risk" section included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk of the 2014 Annual Report for additional information.

Item 4. Controls and Procedures.
Under the direction of our general partner's Chief Executive Officer and Chief Financial Officer, we evaluated our disclosure controls and procedures and internal control over financial reporting and concluded that (i) our disclosure controls and procedures were effective as of June 30, 2015 and (ii) no change in internal control over financial reporting occurred during the quarter ended June 30, 2015, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, and except as previously reported in Item 3. Legal Proceedings of the 2014 Annual Report, we are not currently a party to any significant legal or governmental proceedings.

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 $27.3 million per quarter, or $109.1 million per year (based on units outstanding, as of June 30, 2015, 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;

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- 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.

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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

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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.

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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 wells. 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

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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 wells and/or third-party processing capacity.

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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.

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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

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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 June 30, 2015, we had $879.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated revolving credit facility totaled $421.0 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

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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

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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;

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- 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.

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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

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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.

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

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 36,678,522 publicly held common units at June 30, 2015. 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.

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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;

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- 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.

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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 June 30, 2015, 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 June 30, 2015, Summit Investments, which controls our general partner, indirectly owned 5,293,571 common units out of 41,972,093 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

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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 June 30, 2015, 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. In addition, 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 June 30, 2015, 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 44.5% 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

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- an investor's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.
Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Delaware Law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.
If an investor is not an eligible holder, it may not receive distributions or allocations of income or loss on those common units and those common units will be subject to redemption.
We have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If an investor is not an eligible holder, our general partner may elect not to make distributions or allocate income or loss on that investor's units, and it runs the risk of having its units redeemed by us at the lower of purchase price cost and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our general partner.
The New York Stock Exchange does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.
We have listed our common units on the New York Stock Exchange. Because we are a publicly traded partnership, the New York Stock Exchange does not require us to have, and we do not intend to have, a majority of independent directors on our general partner's board of directors or to establish a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the New York Stock Exchange's shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the New York Stock Exchange corporate governance requirements.

Tax Risks
Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service (the "IRS") were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.
The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.
Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.
If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of 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

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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.

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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.

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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 6. Exhibits.

Exhibit number		Description
3.1		First Amended and Restated Agreement of Limited Partnership of Summit Midstream Partners, LP, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.2		Amended and Restated Limited Liability Company Agreement of Summit Midstream GP, LLC, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.3		Certificate of Limited Partnership of Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 3.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
3.4		Certificate of Formation of Summit Midstream GP, LLC (Incorporated herein by reference to Exhibit 3.4 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
10.1		Contribution Agreement among Summit Midstream Partners Holdings, LLC, Polar Midstream, LLC, Epping Transmission Company, LLC and Summit Midstream Partners, LP dated as of May 6, 2015 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated May 6, 2015 (Commission File No. 001-35666))
10.2		Equity Distribution Agreement, dated June 12, 2015, among the Partnership, the General Partner, the Operating Company, Citigroup Global Markets Inc., Deutsche Bank Securities Inc. and RBC Capital Markets, LLC. (Incorporated herein by reference to Exhibit 1.1 to SMLP's Current Report on Form 8-K dated June 12, 2015 (Commission File No. 001-35666))
31.1		Rule 13a-14(a)/15d-14(a) Certification, executed by Steven J. Newby, President, Chief Executive Officer and Director
31.2		Rule 13a-14(a)/15d-14(a) Certification, executed by Matthew S. Harrison, Executive Vice President and Chief Financial Officer
32.1		Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Steven J. Newby, President, Chief Executive Officer and Director, and Matthew S. Harrison, Executive Vice President and Chief Financial Officer
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 contained in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, formatted in XBRL: (i) Unaudited Condensed Consolidated Balance Sheets, (ii) Unaudited Condensed Consolidated Statements of Operations, (iii) Unaudited Condensed Consolidated Statements of Partners' Capital, (iv) Unaudited Condensed Consolidated Statements of Cash Flows, and (v) Notes to Unaudited Condensed Consolidated Financial Statements.

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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 thereunto duly authorized.

	Summit Midstream Partners, LP (Registrant)
	By: Summit Midstream GP, LLC (its general partner)
August 7, 2015	/s/ Matthew S. Harrison Matthew S. Harrison, Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)