American Midstream Partners, LP
Form 10-Q
August 10, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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: 001-35257

AMERICAN MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	27-0855785
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1400 16th Street, Suite 310	
Denver, CO	80202
(Address of principal executive offices)	(Zip code)

(720) 457-6060
(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. ý Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes ¨ 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	¨	Accelerated filer	ý
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

There were 22,762,504 common units, 8,682,271 Series A Units and 1,301,282 Series B Units of American Midstream Partners, LP outstanding as of August 7, 2015. Our common units trade on the New York Stock Exchange under the ticker symbol “AMID.”

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Glossary of Terms

As generally used in the energy industry and in this Quarterly Report on Form 10-Q (the "Quarterly Report"), the identified terms have the following meanings:

Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bcf	Billion cubic feet.
Btu	British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
/d	Per day.
FERC	Federal Energy Regulatory Commission.
Fractionation	Process by which natural gas liquids are separated into individual components.
GAAP	Accounting principles generally accepted in the United States of America.
Gal	Gallons.
MMBtu	Million British thermal units.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
Mgal	One thousand gallons.
NGL or NGLs	Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Throughput	The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

As used in this Quarterly Report, unless the context otherwise requires, "we," "us," "our," the "Partnership" and similar terms refer to American Midstream Partners, LP, together with its consolidated subsidiaries.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Balance Sheets
(Unaudited, in thousands)

	June 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$348	$499
Accounts receivable	6,263	4,924
Unbilled revenue	18,655	24,619
Risk management assets	1,155	688
Other current assets	8,134	15,554
Current deferred tax assets	5,504	3,086
Total current assets	40,059	49,370
Property, plant and equipment, net	622,590	582,182
Goodwill	134,853	142,236
Intangible assets, net	103,228	106,306
Investment in unconsolidated affiliates	21,935	22,252
Other assets, net	13,982	14,298
Total assets	$936,647	$916,644
Liabilities and Partners’ Capital		
Current liabilities		
Accounts payable	$15,957	$20,326
Accrued gas purchases	9,617	14,326
Accrued expenses and other current liabilities	18,557	25,800
Current portion of long-term debt	737	2,908
Risk management liabilities	69	215
Total current liabilities	44,937	63,575
Asset retirement obligations	35,048	34,645
Other liabilities	287	126
Long-term debt	387,100	372,950
Deferred tax liabilities	11,087	8,199
Total liabilities	478,459	479,495
Commitments and contingencies (See Note 16)		
Convertible preferred units		
Series A convertible preferred units (8,682 thousand and 5,745 thousand units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively)	160,373	107,965
Equity and partners' capital		
General Partner Interests (411 thousand and 392 thousand units issued and outstanding as of June 30, 2015 and December 31, 2014)	(5,218)	(2,450)
Limited Partner Interests (22,757 thousand and 22,670 thousand units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively)	265,319	294,695
Series B convertible units (1,301 thousand and 1,255 thousand units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively)	33,053	32,220
Accumulated other comprehensive income (loss)	(32)	2
Total partners’ capital	293,122	324,467

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Noncontrolling interests	4,693	4,717
Total equity and partners' capital	297,815	329,184
Total liabilities, equity and partners' capital	$936,647	$916,644

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Operations
(Unaudited, in thousands, except for per unit amounts)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenue	$67,198	$77,873	$131,660	$158,241
Gain (loss) on commodity derivatives, net	311	(193)	458	(323)
Total revenue	67,509	77,680	132,118	157,918
Operating expenses:				
Purchases of natural gas, NGLs and condensate	33,334	53,818	62,311	109,039
Direct operating expenses	13,967	11,044	27,834	20,005
Selling, general and administrative expenses	5,571	5,637	12,506	11,230
Equity compensation expense	550	435	2,248	795
Depreciation, amortization and accretion expense	9,250	6,012	18,939	13,644
Total operating expenses	62,672	76,946	123,838	154,713
Gain (loss) on sale of assets, net	(2,970)	—	(2,978)	(21)
Operating income (loss)	1,867	734	5,302	3,184
Other income (expense):				
Interest expense	(3,556)	(1,680)	(6,166)	(3,583)
Earnings in unconsolidated affiliates	4	—	171	—
Net income (loss) before income tax (expense) benefit	(1,685)	(946)	(693)	(399)
Income tax (expense) benefit	(317)	(149)	(473)	(138)
Net income (loss) from continuing operations	(2,002)	(1,095)	(1,166)	(537)
Income (loss) from discontinued operations, net of tax	(31)	(506)	(26)	(556)
Net income (loss)	(2,033)	(1,601)	(1,192)	(1,093)
Net income (loss) attributable to noncontrolling interests	32	66	46	174
Net income (loss) attributable to the Partnership	$(2,065)	$(1,667)	$(1,238)	$(1,267)
General Partner's Interest in net income (loss)	$(25)	$(22)	$(14)	$(15)
Limited Partners' Interest in net income (loss)	$(2,040)	$(1,645)	$(1,224)	$(1,252)
Distribution declared per common unit (a)	$0.4725	$0.4625	$0.9450	$0.9150
Limited partners' net income (loss) per common unit (See Note 4 and Note 13):				
Basic and diluted:				
Income (loss) from continuing operations	$(0.35)	$(0.55)	$(0.53)	$(0.92)
Income (loss) from discontinued operations	—	(0.04)	—	(0.05)
Net income (loss)	$(0.35)	$(0.59)	$(0.53)	$(0.97)
Weighted average number of common units outstanding:				
Basic and diluted	22,757	11,139	22,730	10,496

(a) Distributions declared and paid during the three and six months ended June 30, 2015 and 2014 related to prior periods' earnings.

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income
(Unaudited, in thousands)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$(2,033)	$(1,601)	$(1,192)	$(1,093)
Unrealized gain (loss) on postretirement benefit plan assets and liabilities	(23)	10	(34)	46
Comprehensive income (loss)	(2,056)	(1,591)	(1,226)	(1,047)
Less: Comprehensive income (loss) attributable to noncontrolling interests	32	66	46	174
Comprehensive income (loss) attributable to Partnership	$(2,088)	$(1,657)	$(1,272)	$(1,221)

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Changes in Partners’ Capital
and Noncontrolling Interest
(Unaudited, in thousands)

	General Partner Interest	Limited Partner Interest	Series B Convertible Units	Accumulated Other Comprehensive Income	Total Partners' Capital	Noncontrolling Interest
Balances at December 31, 2013	$2,696	$71,039	$—	$104	$73,839	$4,628
Net income (loss)	(15)	(1,252)	—	—	(1,267)	174
Issuance of common units to public, net of offering costs	—	86,904	—	—	86,904	—
Issuance of Series B units	—	—	31,052	—	31,052	—
Unitholder contributions	1,276	—	—	—	1,276	—
Unitholder distributions	(1,192)	(18,093)	—	—	(19,285)	—
Issuance and exercise of warrant	(7,164)	7,164	—	—	—	—
Net distributions to noncontrolling interests	—	—	—	—	—	(226)
Acquisitions of noncontrolling interests	—	21	—	—	21	(29)
LTIP vesting	(511)	639	—	—	128	—
Tax netting repurchase	—	(151)	—	—	(151)	—
Equity compensation expense	698	—	—	—	698	—
Other comprehensive loss	—	—	—	46	46	—
Balances at June 30, 2014	$(4,212)	$146,271	$31,052	$150	$173,261	$4,547
Balances at December 31, 2014	$(2,450)	$294,695	$32,220	$2	$324,467	$4,717
Net income (loss)	(14)	(1,224)	—	—	(1,238)	46
Issuance of Series B units	—	—	833	—	833	—
Unitholder contributions	376	—	—	—	376	—
Unitholder distributions	(3,004)	(29,800)	—	—	(32,804)	—
Net distributions to noncontrolling interests	—	—	—	—	—	(70)
LTIP vesting	(2,178)	2,373	—	—	195	—
LTIP tax netting unit repurchase	—	(725)	—	—	(725)	—
Equity based compensation	2,052	—	—	—	2,052	—
Other comprehensive income	—	—	—	(34)	(34)	—
Balances at June 30, 2015	$(5,218)	$265,319	$33,053	$(32)	$293,122	$4,693

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

American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(Unaudited, in thousands)

	Six months ended June 30, 2015	2014
Cash flows from operating activities		
Net income (loss)	$(1,192)	$(1,093)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	18,939	13,644
Amortization of deferred financing costs	667	847
Amortization of weather derivative premium	475	554
Unrealized (gain) loss on commodity derivatives, net	(213)	113
Non-cash compensation	2,294	730
Postretirement expense (benefit)	18	(23)
(Gain) loss on sale of assets, net	2,978	106
Loss on impairment of noncurrent assets held for sale	—	673
Deferred tax expense (benefit)	457	(161)
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	(1,331)	(556)
Unbilled revenue	5,964	(2,083)
Risk management assets and liabilities	(875)	(965)
Other current assets	1,041	1,547
Other assets, net	37	22
Accounts payable	6,200	(851)
Accrued gas purchases	(4,709)	(188)
Accrued expenses and other current liabilities	(1,293)	680
Asset retirement obligations	—	(623)
Other liabilities	163	38
Net cash provided by operating activities	29,620	12,411
Cash flows from investing activities		
Cost of acquisitions, net of cash acquired	7,383	(110,909)
Additions to property, plant and equipment	(79,734)	(13,229)
Proceeds from disposals of property, plant and equipment	3,876	6,202
Investment in unconsolidated affiliate	(626)	—
Return of capital from unconsolidated affiliate	1,329	—
Restricted cash	6,475	—
Net cash used in investing activities	(61,297)	(117,936)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	(348)	86,904
Unitholder contributions	330	1,276
Unitholder distributions	(24,364)	(13,793)
Issuance of Series A Units	45,000	—
Issuance of Series B Units	—	30,000
Acquisition of noncontrolling interests	—	(8)
Net distributions to noncontrolling interests	(70)	(226)
LTIP tax netting unit repurchase	(725)	(151)
Payment of deferred financing costs	(276)	(154)

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Payments on other debt	(2,171)	(1,644)
Borrowings on other debt	—	170
Payments on long-term debt	(123,650)	(75,220)
Borrowings on long-term debt	137,800	80,985
Net cash provided by financing activities	31,526	108,139
Net increase (decrease) in cash and cash equivalents	(151)	2,614
Cash and cash equivalents		
Beginning of period	499	393
End of period	$348	$3,007
Supplemental cash flow information		
Interest payments, net	$5,572	$2,718
Supplemental non-cash information		
Increase (decrease) in accrued property, plant and equipment	$(16,897)	$9,501
Accrued paid in-kind unitholder distributions for Series A Units	7,607	5,760
In-kind unitholder distributions for Series B Units	833	1,052

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

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American Midstream Partners, LP and Subsidiaries
Notes to Condensed Consolidated Financial Statements
(Unaudited)
1. Organization and Basis of Presentation

General

American Midstream Partners, LP (the "Partnership", "we", "us", or "our"), was formed on August 20, 2009 as a Delaware limited partnership for the purpose of operating, developing and acquiring a diversified portfolio of midstream energy assets. The Partnership's general partner, American Midstream GP, LLC (the "General Partner"), is 95% owned by High Point Infrastructure Partners, LLC ("HPIP") and 5% owned by AIM Midstream Holdings, LLC. We hold our assets in a series of wholly owned limited liability companies, two limited partnerships and a corporation. Our capital accounts consist of notional general partner units and limited partner interests.

Nature of Business

We are engaged in the business of gathering, treating, processing, and transporting natural gas, fractionating NGLs, transporting oil and storing specialty chemical products through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, four marine terminal sites, three interstate pipelines, five intrastate pipelines and one oil pipeline. We also own a 66.7% non-operating interest in Main Pass Oil Gathering, LP ("MPOG"), a crude oil gathering and processing system, a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant, and a 46% non-operated interest in Mesquite, an off-spec condensate fractionation project. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links producers of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate more than 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.7 million barrels of storage capacity across four marine terminal sites.

Basis of Presentation

These unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from consolidated audited financial statements but does not include disclosures required by GAAP for annual periods. The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the respective interim periods.

Our financial results for the three and six months ended June 30, 2015, are not necessarily indicative of the results that may be expected for the full year ended December 31, 2015. These unaudited condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014 (“Annual Report”) filed with the Securities and Exchange Commission (the "SEC") on March 10, 2015.

Consolidation Policy

The accompanying condensed consolidated financial statements include accounts of American Midstream Partners, LP, and its controlled subsidiaries. All significant inter-company accounts and transactions have been eliminated in the preparation of the accompanying condensed consolidated financial statements. We hold a 50% undivided interest in the Burns Point natural gas processing plant in which we are responsible for our proportionate share of the costs and expenses of the facility. Our condensed consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of this undivided interest. As of June 30, 2015, we also hold a 92.2% undivided interest in the Chatom Processing and Fractionation facility (the "Chatom System"). Our condensed consolidated financial statements reflect the accounts of the Chatom System and the interests in the Chatom System held by non-affiliated working interest owners are reflected as noncontrolling interests in the Partnership's condensed consolidated financial statements.

The Partnership accounts for its 66.7% non-operated interest in MPOG and its 46.0% non-operated interest in Mesquite under the equity method.

Use of Estimates

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When preparing condensed consolidated financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and assumptions are based on information available at the time such estimates and assumptions are made. Adjustments made with respect to the use of these estimates and assumptions often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates and assumptions are used in, among other things i) estimating unbilled revenues, product purchases and operating and general and administrative costs, ii) developing fair value estimates, including assumptions for future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

2. Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting standards for revenue recognition. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017, including interim periods therein, as a result of the FASB's recent decision to defer the effective date by one year. We are currently evaluating the method of adoption and impact this standard will have on our condensed consolidated financial statements and related disclosures.

In February 2015, the FASB issued ASU No. 2015-02, Amendments to the Consolidation Analysis. This guidance amends the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015, and early adoption is permitted. The Partnership is currently evaluating the potential impact this standard will have on its condensed consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. This amendment requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, including interim periods therein, and is applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. Given the Partnership's debt issuance costs relate to its revolving debt Credit Facility, the Partnership does not anticipate this standard to alter its current accounting for such costs.

In April 2015, the FASB issued ASU No. 2015-06, Earnings Per Share (Topic 260). This guidance clarifies the process for updating historical earnings per unit disclosures when a drop-down transaction occurs between entities under common control. Pursuant to the amendment, the previously reported earnings per unit measure presented in the historical financial statements would not change as a result of the drop-down transaction. ASU 2015-06 is effective for annual reporting periods beginning after December 15, 2015, and for interim periods within those fiscal years. Early adoption is permitted. The Partnership has evaluated this guidance and determined it is consistent with our policy and historical presentation of earnings per unit.

3. Acquisitions and Divestitures

Costar Acquisition

On October 14, 2014, the Partnership acquired 100% of the membership interests of Costar Midstream, L.L.C. ("Costar") from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC, in exchange for $258.0 million in cash and 6.9 million of the Partnership's common units representing Limited Partner interests, or common units (the "Costar Acquisition"). Costar is an onshore gathering and processing company with its primary gathering, processing, fractionation, and off-spec condensate treating and stabilization assets in East Texas and the Permian basin, with a significant crude oil gathering system project under development in the Bakken oil play.

The Costar Acquisition was accounted for using the acquisition method of accounting and as a result, the aggregate purchase price was allocated to the assets acquired, liabilities assumed and a noncontrolling interest in a Costar subsidiary based on their respective fair values as of the acquisition date. The excess of the aggregate purchase price over the fair values of the assets acquired, liabilities assumed and the noncontrolling interest was classified as goodwill, which is attributable to future prospective customer agreements expected to be obtained as a result of the acquisition. The operating systems acquired have been included in the Partnership’s Gathering and Processing segment from the acquisition date.

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During the first quarter of 2015, we reached an agreement on certain working capital matters with the Costar sellers, resulting in a decrease to goodwill of $0.2 million.

In the second quarter of 2015, we reached an agreement with the Costar sellers regarding certain capital expenditures that we have incurred, or will incur, that were not known at the time of closing, which resulted in a decrease to goodwill and cash consideration transferred of $7.2 million.

The following table summarizes the fair value of consideration transferred to acquire Costar and the allocation of that amount to the assets acquired, liabilities assumed and the noncontrolling interest based upon their respective fair values as of the acquisition date (in thousands).

Fair value of consideration transferred:	
Cash	$258,001
Limited partner common units	147,296
Total fair value of consideration	$405,297
Fair Value of assets acquired, liabilities assumed and noncontrolling interest:	
Working capital	$8,152
Property, plant and equipment:	
Processing plants	$48,357
Pipelines	128,799
Land	1,244
Buildings	682
Equipment	9,827
Construction in progress	16,146
Total property, plant and equipment	205,055
Investment in unconsolidated affiliate	11,884
Intangible assets:	
Customer relationships	53,400
Dedicated acreage	32,000
Goodwill	95,025
Noncontrolling interest	(219)
	$405,297

The fair value of the common units of $147.3 million differs from the amount determined using the market price of such units on the date of the acquisition as a result of restrictions which require the sellers to hold the units for specified periods of time. The fair value of Limited Partner common units issued in the transaction was determined using an option pricing model and the following key assumptions: i) the closing unit market price on the day of the acquisition, ii) the contractual holding periods, iii) historical unit price volatility for the Partnership and its peers, and iv) a risk-free rate of return.

The fair value of property, plant and equipment was determined using both the cost and market approaches which required significant Level 3 inputs. Key assumptions included i) estimated replacement costs for individual assets or asset groups, ii) estimated remaining useful lives for the acquired assets, and iii) recent market transactions for similar assets. The fair value of intangible assets was determined using the income approach which also required significant Level 3 inputs. Key assumptions included i) estimated throughput volumes, ii) forward market prices for natural gas and NGLs as of the acquisition date, iii) estimated future operating and development cash flows, and iv) discount rates ranging from 11.0% to 16.0%.

The intangible assets acquired relate to existing customer relationships that Costar had at the time of the acquisition, as well as agreements with two producers under which Costar agreed to construct and operate gathering and processing facilities in exchange for the producers' agreements to dedicate certain acreage and related production to those facilities. Working capital includes $11.2 million of accounts receivable, all of which were subsequently collected.

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For the three and six months ended June 30, 2015, Costar contributed revenue of $24.2 million and $45.6 million, respectively, and net income of $0.6 million and $1.8 million, respectively, attributable to the Partnership's Gathering and Processing segment.

Lavaca Acquisition

On January 31, 2014, the Partnership acquired approximately 120 miles of high- and low-pressure pipelines and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas from Penn Virginia Corporation (NYSE: PVA) ("PVA") for $104.4 million in cash (the "Lavaca Acquisition"). The Lavaca Acquisition was financed with proceeds from the Partnership's January 2014 equity offering and from the issuance of Series B Units to our General Partner.

The Lavaca Acquisition was accounted for using the acquisition method of accounting and, as a result, the purchase price was allocated to the assets acquired upon their respective fair values as of the acquisition date. The excess of the purchase price over the fair value of the assets acquired was classified as goodwill.

The following table summarizes the final allocation of the purchase price to the assets acquired based upon their respective fair values as of the acquisition date (in thousands):

Property, plant and equipment:	
Land	$2
Pipelines	58,737
Equipment	753
Total property, plant and equipment	59,492
Intangible assets	21,350
Goodwill	23,567
Total cash consideration	$104,409

The fair value of property, plant and equipment was determined using the cost approach which required significant Level 3 inputs. Key assumptions included i) estimated replacement costs for individual assets or asset groups and ii) estimated remaining useful lives for the acquired assets. The fair value of intangible assets was determined using the income approach which also required significant Level 3 inputs. Key assumptions included i) estimated throughput volumes, ii) future operating and development cash flows, and iii) a discount rate of 10.5%.

The intangible assets acquired relate to a gas gathering agreement under which PVA has dedicated certain acreage and related production to the acquired facilities.

For the three and six months ended June 30, 2015, Lavaca contributed revenue of $5.9 million and $11.9 million, respectively, and net income of $2.3 million and $4.5 million, respectively, attributable to the Partnership's Gathering and Processing segment. For the three and six months ended June 30, 2014, Lavaca contributed revenue of $3.7 million and $6.0 million, respectively, and net income of $0.6 million and $2.2 million, respectively, attributable to the Partnership's Gathering and Processing segment.

Other Acquisitions

Investment in Unconsolidated Affiliates

On August 11, 2014, the Partnership acquired a 66.7% non-operated interest in MPOG, an offshore oil gathering system, for a net purchase price of $12.0 million, which was financed with borrowings from the Partnership's credit facility. Although the Partnership owns a majority interest in MPOG, the ownership structure requires unanimous approval of all owners on decisions impacting the operation of the assets and any changes in ownership structure. Therefore, the Partnership's voting rights are not proportional to its obligation to absorb losses or receive returns. The Partnership accounts for its 66.7% interest using the equity method.

For three and six months ended June 30, 2015, the Partnership recorded less than $0.1 million and $0.2 million, respectively, in earnings from MPOG. The Partnership received cash distributions of $0.5 million and $1.5 million for the three and six months ended June 30, 2015, respectively. The excess of the cash distributions received over the earnings recorded from MPOG is classified as a return of capital within the investing section of our consolidated statement of cash flows.

Williams Pipeline Acquisition

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In the first quarter of 2014, the Partnership acquired natural gas pipeline facilities that are contiguous to and connect with our High Point System in our Transmission segment located in offshore Louisiana from Transcontinental Gas Pipe Line Company, LLC, a subsidiary of Williams Partners, LP. for $6.5 million in cash. The acquisition was subject to FERC approval of the seller's application to abandon by sale to us the pipeline facilities and to permit the facilities to serve a gathering function, exempt from FERC's jurisdiction. The FERC granted approval of the application during the first quarter of 2014, and the purchase and sale agreement closed on March 14, 2014. The purchase price was allocated to pipelines using the income approach which required certain Level 3 inputs.

Divestitures

On June 1, 2015, the Partnership disposed of certain non-strategic off-shore transmission assets in Louisiana with a net book value of $3.0 million for nominal proceeds, resulting in a non-cash loss on disposal of $3.0 million.

On March 31, 2014, the Partnership completed the sale of certain gathering and processing assets in Madison County, Texas. We received $6.1 million in cash proceeds related to the sale, which approximated its net book value.

4. Discontinued Operations

The Partnership continues to classify the terminal asset in Salisbury, Maryland as held for sale as we are continuing negotiations for the sale of those assets, contingent upon the purchaser’s completion of due diligence. The net book value of the assets and liabilities attributable to the terminal asset comprise less than $0.1 million of Other current assets, $1.2 million of Other assets, net, and less than $0.1 million of Accrued expenses and other current liabilities as of June 30, 2015 and December 31, 2014.

We have classified these assets as discontinued operations within our condensed consolidated statement of operations. Accordingly, we reclassified the disposal group's results of operations from our results of continuing operations to Income (loss) from discontinued operations, net of tax in our accompanying condensed consolidated statement of operations for all periods presented. We elected not to present separately the operating, investing and financing cash flows related to the disposal groups in our accompanying condensed consolidated statement of cash flows as this activity was immaterial for all periods presented. The following table presents the revenue, expense and gain (loss) from operations of disposal groups associated with the assets classified as held for sale for the three and six months ended June 30, 2015 and 2014 (in thousands, except per unit amounts):

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenue	$10	$212	$74	$449
Expense	(61)	(268)	(116)	(545)
Loss on impairment of property, plant and equipment	—	(673)	—	(673)
Loss on sale of assets	—	(65)	—	(87)
Income tax benefit	20	288	16	300
Income (loss) from operations of disposal groups, net of tax	$(31)	$(506)	$(26)	$(556)
Limited partners' net income (loss) per unit from discontinued operations (basic and diluted)	$—	$(0.04)	$—	$(0.05)

5. Concentration of Credit Risk and Trade Accounts Receivable

Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links customers of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. As a result of recent acquisitions and geographic diversification, we have reduced the concentration of trade receivable balances due from these customer groups, and as such reduced the concentration which may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. We maintain allowances for potentially uncollectible accounts receivable; however, for the three and six months ended June 30, 2015 and 2014, no allowances on or significant write-offs of accounts receivable were recorded.

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During the three and six months ended June 30, 2015, no individual customer accounted for 10% or more of the Partnership's consolidated revenue.

6. Other Current Assets

Other current assets consist of the following (in thousands):

	June 30, 2015	December 31, 2014
Prepaid insurance	$1,922	$4,162
Restricted cash	—	6,475
Other current assets	6,212	4,917
	$8,134	$15,554

Restricted cash of $6.5 million as of December 31, 2014 consisted of a cash-backed letter of credit related to Costar operations that the Partnership was contractually obligated to maintain after the Costar Acquisition. The Partnership was released from this obligation in January 2015. Other current assets primarily consist of natural gas imbalances and amounts due from related parties.

7. Derivatives

Commodity Derivatives

To minimize the effect of commodity price changes and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price declines while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our General Partner. Currently, our commodity derivatives are in the form of swaps. As of June 30, 2015, the aggregate notional volume of our commodity derivatives was 4.3 million gallons of NGLs, natural gasoline, and crude oil equivalent.

We enter into commodity contracts with multiple counterparties, and in some cases, may be required to post collateral with our counterparties in connection with our derivative positions. As of June 30, 2015, we were not required to post collateral with any counterparty. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place that permit us to offset our commodity derivative asset and liability positions with our counterparties.

We did not designate any of our commodity derivatives as hedges for accounting purposes. As a result, our commodity derivatives are accounted for at fair value in our condensed consolidated balance sheets with changes in fair value recognized currently in earnings.

Interest Rate Swap

We entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows. As of June 30, 2015, the notional amount of our interest rate swap was $100.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap expired

August 1, 2015.

Weather Derivative

In the second quarter of 2015, we entered into a weather derivative to mitigate the impact of potential unfavorable weather to our operations under which we could receive payments totaling up to $10.0 million in the event that a hurricane or hurricanes of certain strength pass through the area as identified in the derivative agreement. The weather derivatives are accounted for using the intrinsic value method, under which the fair value of the contract was zero and any amounts received are recognized as gains during the period received. The weather derivatives were entered into with a single counterparty, and we were not required to post collateral.

We paid premiums of $0.9 million in 2015, which are recorded as current Risk management assets on our condensed consolidated balance sheet and are being amortized to Direct operating expenses on a straight-line basis over the term of the contract of one year. Unamortized amounts associated with the weather derivatives were approximately $0.8 million as of June 30, 2015.

As of June 30, 2015 and December 31, 2014, the value associated with our commodity derivatives, interest rate swap, and weather derivative were recorded in our condensed consolidated balance sheets, under the captions as follows (in thousands):

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Balance Sheet Classification	Gross Risk Management Assets June 30, 2015	Gross Risk Management Assets December 31, 2014	Gross Risk Management Liabilities June 30, 2015	Gross Risk Management Liabilities December 31, 2014	Net Risk Management Assets (Liabilities) June 30, 2015	Net Risk Management Assets (Liabilities) December 31, 2014
Current	$1,155	$688	$—	$—	$1,155	$688
Noncurrent	—	—	—	—	—	—
Total assets	$1,155	$688	$—	$—	$1,155	$688
Current	$—	$—	$(69)	$(215)	$(69)	$(215)
Noncurrent	—	—	—	—	—	—
Total liabilities	$—	$—	$(69)	$(215)	$(69)	$(215)

For the three and six months ended June 30, 2015 and 2014, respectively, the realized and unrealized gains (losses) associated with our commodity derivatives, interest rate swap instrument and weather derivative were recorded in our condensed consolidated statements of operations, under the captions as follows (in thousands):

Statement of Operations Classification	Three months ended June 30, Gain (loss) on derivatives Realized	Three months ended June 30, Gain (loss) on derivatives Unrealized	Six months ended June 30, Gain (loss) on derivatives Realized	Six months ended June 30, Gain (loss) on derivatives Unrealized
2015				
Gain (loss) on commodity derivatives, net	$252	$59	$391	$67
Interest expense	(101)	98	(203)	146
Direct operating expenses	(234)	—	(475)	—
Total	$(83)	$157	$(287)	$213
2014				
Gain (loss) on commodity derivatives, net	$(80)	$(113)	$(182)	$(141)
Interest expense	(109)	38	(213)	28
Direct operating expenses	(269)	—	(553)	—
Total	$(458)	$(75)	$(948)	$(113)

8. Fair Value Measurement

We believe the carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the short-term maturity of these instruments.

The recorded value of the amounts outstanding under the credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates and the short-term nature of borrowings and repayments under the credit facility.

The fair value of all derivatives instruments is estimated using a market valuation methodology based upon forward commodity price curves, volatility curves as well as other relevant economic measures, if necessary. Discount factors may be utilized to extrapolate a forecast of future cash flows associated with long dated transactions or illiquid market points. The inputs are obtained from independent pricing services, and we have made no adjustments to the obtained prices.

We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivatives contracts held. We will recognize transfers between levels at the end of the reporting period in which the transfer occurred. There were no such transfers for the six months ended June 30, 2015 and 2014.

Fair Value of Financial Instruments

The following table sets forth by level within the fair value hierarchy, our commodity derivative instruments and interest rate swap, included as part of Risk management assets and Risk management liabilities within our condensed consolidated balance sheets, that were measured at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 (in thousands):

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	Carrying Amount	Estimated Fair Value of the Asset (Liability) Level 1	Level 2	Level 3	Total
Commodity derivative instruments, net					
June 30, 2015	$353	$—	$353	$—	$353
December 31, 2014	286	—	286	—	286
Interest rate swap					
June 30, 2015	$(69)	$—	$(69)	$—	$(69)
December 31, 2014	(215)	—	(215)	—	(215)

The unamortized portion of the premium paid to enter the weather derivative described in Note 7 "Derivatives" is included within Risk management assets on our condensed consolidated balance sheet but is not included as part of the above table as it is recorded at amortized carrying cost, not fair value.

9. Property, Plant and Equipment, Net

Property, plant and equipment, net, as of June 30, 2015 and December 31, 2014 were as follows (in thousands):

	Useful Life (in years)	June 30, 2015	December 31, 2014
Land	N/A	$5,282	$5,282
Construction in progress	N/A	90,085	77,550
Base gas	N/A	1,108	1,108
Buildings and improvements	4 to 40	9,708	6,855
Processing and treating plants	8 to 40	81,404	80,837
Pipelines	3 to 40	479,749	451,341
Compressors	4 to 20	30,506	24,548
Dock	20 to 40	8,105	8,072
Tanks, truck rack and piping	20 to 40	32,826	30,079
Equipment	8 to 20	9,474	8,855
Computer software	5	3,856	3,490
Total property, plant and equipment		752,103	698,017
Accumulated depreciation		(129,513)	(115,835)
Property, plant and equipment, net		$622,590	$582,182

Of the gross property, plant and equipment balances at June 30, 2015 and December 31, 2014, $104.4 million and $101.9 million, respectively, were related to AlaTenn, Midla and HPGT, our FERC regulated interstate and intrastate assets.

Capitalized interest was $0.5 million and $0.1 million for the three months ended June 30, 2015 and 2014, respectively, and $0.7 million and $0.2 million for the six months ended June 30, 2015 and 2014, respectively.

Depreciation expense was $7.6 million and $4.7 million for the three months ended June 30, 2015 and 2014, respectively, and $15.5 million and $11.1 million for the six months ended June 30, 2015 and 2014, respectively.

10. Goodwill and Intangible Assets, Net

The carrying value of goodwill as of June 30, 2015 and December 31, 2014, was $134.9 million and $142.2 million, respectively. See Note 3 "Acquisitions and Divestitures" for discussion regarding the change in goodwill from December 31, 2014 to June 30, 2015. Goodwill as of June 30, 2015 consisted of $118.6 million and $16.3 million related to our Gathering and Processing and Terminal segments, respectively. Goodwill as of December 31, 2014 consisted of $125.9 million and $16.3 million related to our Gathering and Processing and Terminal segments, respectively.

The goodwill associated with our Gathering and Processing segment relates to the Costar and Lavaca Acquisitions and primarily represent strategic developmental locations to grow the business within the segment. The goodwill associated with our Terminal segment was contributed to the Partnership as part of the Partnerships' acquisition of Blackwater Midstream Holdings LLC ("Blackwater") and other related subsidiaries from an affiliate of HPIP (the "Blackwater Acquisition"). Goodwill was recorded as

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a result of the excess of the investment by an affiliate of HPIP in Blackwater over the fair market value of the identifiable net assets and customer contracts acquired.

Intangible assets, net, consists of customer contracts, relationships and dedicated acreage agreements identified as part of the Costar Acquisition, Lavaca Acquisition and Blackwater Acquisition. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging from 5 months to thirty years. Intangible assets, net, consist of the following (in thousands):

	June 30, 2015	December 31, 2014
Gross carrying amount:		
Customer contracts	$12,101	$12,101
Customer relationships	53,400	53,400
Dedicated acreage	53,350	53,350
	$118,851	$118,851
Accumulated amortization:		
Customer contracts	$(12,013)	$(11,110)
Customer relationships	(1,815)	(553)
Dedicated acreage	(1,795)	(882)
	$(15,623)	$(12,545)
Net carrying amount:		
Customer contracts	$88	$991
Customer relationships	51,585	52,847
Dedicated acreage	51,555	52,468
	$103,228	$106,306

Amortization expense on our intangible assets totaled $1.5 million and $1.2 million for the three months ended June 30, 2015 and 2014, respectively, and $3.1 million and $2.1 million for the six months ended June 30, 2015 and 2014, respectively.

11. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities were as follows (in thousands):

	June 30, 2015	December 31, 2014
Accrued capital expenditures	$8,225	$17,134
Accrued expenses	5,587	7,036
Gas imbalances payable	895	1,069
Other	3,850	561
	$18,557	$25,800

12. Debt Obligations

Our outstanding borrowings under the credit facility were (in thousands):

	June 30, 2015	December 31, 2014
Revolving credit facility	$387,100	$372,950
Other debt	737	2,908
Total debt	387,837	375,858

Less: current portion	737	2,908
Long-term debt	$387,100	$372,950

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On September 5, 2014, the Partnership entered into an amended and restated credit agreement (the "Credit Agreement"), which provides for a maximum borrowing equal to $500.0 million, with the ability to further increase the borrowing capacity subject to lender approval. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

Our obligations under the Credit Agreement are secured by a first mortgage in favor of the lenders in the majority of our real property. Advances made under the Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the Credit Agreement include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, which is September 5, 2019.

The Credit Agreement contains certain financial covenants, including the requirement that our indebtedness not exceed 4.75 times adjusted consolidated EBITDA (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted Consolidated EBITDA) and a minimum interest coverage ratio test (not less than 2.50). The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $500.0 million. In addition to the financial covenants described above, the Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

For the six months ended June 30, 2015 and 2014, the weighted average interest rate on borrowings under the Credit Agreement was approximately 3.90% and 4.18%, respectively.

As of June 30, 2015, our consolidated total leverage was 5.00 and our interest coverage ratio was 8.48, which were in compliance with the consolidated total leverage ratio and interest coverage ratio tests in accordance with the financial covenants required in the Credit Agreement. At June 30, 2015 and December 31, 2014, letters of credit outstanding under the Credit Agreement were $1.6 million.

Other debt

Other debt represents insurance premium financing in the original amount of $3.3 million bearing interest at 3.95% per annum, which is repayable in equal monthly installments of approximately $0.4 million through the third quarter of 2015.

13. Partners’ Capital and Convertible Preferred Units

Our capital accounts are comprised of approximately 1.2% notional general partner interests and 98.8% limited partner interests. Our limited partners have limited rights of ownership as provided for under our partnership agreement and the right to participate in our distributions. Our General Partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the incentive distribution rights that are non-voting limited partner rights held by our General Partner.

Our General Partner holds and participates in the distribution of Series B Units with such distributions being made in cash or with paid-in-kind Series B Units at the election of the Partnership. The holders of Series B Units are entitled to vote along with the holders of Limited Partner common units and such units will automatically convert to Limited Partner common units on January 31, 2016.

HPIP holds and participates in the distribution of Series A-1 Units with such distributions being made in paid-in-kind Series A-1 Units, cash or a combination thereof, at the election of the board of directors of our General Partner through the distribution for the earlier of (a) the quarter ended March 31, 2016 or (b) the time in which the Series A-1 Units are converted into common units. The Series A-1 Units are entitled to vote along with Limited Partner common unitholders and such units are currently convertible to Limited Partner common units.

Series A-2 Units

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On March 30, 2015 and June 30, 2015, we entered into two Series A-2 Convertible Preferred Unit Purchase Agreements with Magnolia Infrastructure Partners, LLC (an affiliate of HPIP) pursuant to which the Partnership issued, in separate private placements, newly-designated Series A-2 Units (the “Series A-2 Units”) representing limited partnership interests in the Partnership. As a result, the Partnership issued a total of 2,571,430 Series A-2 Units for approximately $45.0 million in aggregate proceeds during the six months ended. The Series A-2 Units will participate in distributions of the Partnership along with common units in a manner identical to the existing Series A Units (such previously existing Series A Units now referred to as the "Series A-1 Units" and, together with the Series A-2 Units, the "Series A Units"), with such distributions being made in cash or with paid-in-kind Series A Units at the election of the board of directors of our General Partner. The board of directors of our General Partner has, to date, elected to pay Series A distributions using paid-in-kind Series A Units.

On July 27, 2015, we entered into the Fifth Amendment (the “Fifth Amendment”) to our partnership agreement. The Fifth Amendment grants us the right (the “Call Right”) to require the holders of the Series A-2 Units (the “Series A-2 Holders”) to sell, assign and transfer all or a portion of the then outstanding Series A-2 Units to us for a purchase price of $17.50 per Series A-2 Unit (subject to appropriate adjustment for any equity distribution, subdivision or combination of equity interests in the Partnership). We may exercise the Call Right at any time after January 1, 2016, in connection with our or our affiliate’s acquisition of assets or equity from ArcLightEnergy Partners Fund V, L.P., or one of its affiliates, for a purchase price in excess of $100 million. We may not exercise the Call Right with respect to any Series A-2 Units that a Series A-2 Holder has elected to convert into common units on or prior to the date we have provided notice of our intent to exercise the Call Right, and may not exercise the Call Right if doing so would result in a default under any of our or our affiliates’ financing agreements or obligations.

Equity Offerings

On January 29, 2014, the Partnership and certain of its affiliates entered into an underwriting agreement with Barclays Capital Inc. and UBS Securities LLC (the “Underwriters”), providing for the issuance and sale by the Partnership, and the purchase by the Underwriters, of 3,400,000 Limited Partner common units representing limited partner interests in the Partnership at a price to the public of $26.75 per common unit. The Partnership used the net proceeds of $86.9 million to fund a portion of the Lavaca Acquisition.

Issuance and Exercise of Warrant

Effective February 5, 2014, we issued to AIM Midstream Holdings, LLC a warrant to purchase up to 300,000 Limited Partner common units of the Partnership at an exercise price of $0.01 per common unit (the “Warrant”). The Warrant was exercised on February 21, 2014, resulting in the issuance of approximately 300,000 Limited Partner common units. The value of the Warrant of $7.2 million was determined based on the close price of $23.89 of the Limited Partner common units on the exercise date.

Equity Outstanding

The number of units outstanding as of June 30, 2015 and December 31, 2014, respectively, were as follows (in thousands):

	June 30, 2015	December 31, 2014
Series A convertible preferred units	8,682	5,745
Series B convertible units	1,301	1,255
Limited Partner common units	22,757	22,670
General Partner units	411	392

Distributions

We made cash distributions as follows (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Series A convertible preferred units	—	1,338	—	2,658
Limited Partner common units	10,753	5,152	21,466	10,049
General Partner units	159	76	317	148
General Partners' incentive distribution rights	1,293	527	2,581	937
	$12,205	$7,093	$24,364	$13,792

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The Partnership executed a fourth amendment to its partnership agreement (the "Fourth Amendment"), which became effective March 30, 2015, related to its outstanding Series A Units. As a result of the Fourth Amendment, distributions on Series A Units will be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the board of directors of our General Partner, which began with the distribution for the three months ended June 30, 2014 and will continue through the distribution for the earlier of (a) the quarter ended March 31, 2016 or (b) the time in which the Series A-1 Units are converted into common units. At June 30, 2015, we have accrued $4.2 million for the paid-in-kind Series A Units. The distributions will be made in the third quarter of 2015.

Net Income (Loss) attributable to Limited Partner Common Units

Net income (loss) is allocated to the General Partner and the limited partners in accordance with their respective ownership percentages, after giving effect to contractual distributions on Series A Units, declared distributions on the Series B Units, common units representing Limited Partner interests and to the General Partner units, including incentive distribution rights. Unvested unit-based payment awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net income per limited partner unit. Basic and diluted net income (loss) per limited partner unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding Limited Partner common units during the period. We determined basic and diluted net income (loss) per limited partner unit as follows, (in thousands, except per unit amounts):

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net income (loss) from continuing operations	$(2,002)	$(1,095)	$(1,166)	$(537)
Less: Net income (loss) attributable to noncontrolling interests	32	66	46	174
Net income (loss) from continuing operations attributable to the Partnership	(2,034)	(1,161)	(1,212)	(711)
Less:				
Contractual distributions on Series A Units	4,196	3,917	7,607	7,098
Declared distributions on Series B Units	413	560	833	1,052
General partner's distribution	1,452	603	2,899	1,085
General partner's share in undistributed loss	(234)	(149)	(422)	(262)
Net income (loss) from continuing operations available to limited partners	(7,861)	(6,092)	(12,129)	(9,684)
Net income (loss) from discontinued operations available to limited partners	(31)	(499)	(26)	(549)
Net income (loss) available to limited partners	$(7,892)	$(6,591)	$(12,155)	$(10,233)
Weighted average number of units used in computation of limited partners' net (loss) income per unit (basic and diluted)	22,757	11,139	22,730	10,496
Limited partners' net loss per common unit				
Basic and diluted:				
Loss from continuing operations	$(0.35)	$(0.55)	$(0.53)	$(0.92)
Loss from discontinued operations	—	(0.04)	—	(0.05)
Net loss	$(0.35)	$(0.59)	$(0.53)	$(0.97)

14. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs personnel who provide support to our operations. The board of directors of our General Partner grants awards under its long-term incentive plan ("LTIP") for its employees, consultants and directors who perform services for it or its affiliates. At June 30, 2015 and December 31, 2014, 399,832 and 688,976 units, respectively, were available for future grant under the LTIP.

LTIP awards are subject to forfeiture until the vesting date. The LTIP is administered by the board of directors of our General Partner which, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash. Although our General Partner has the option to settle in cash upon the vesting of phantom units, our General Partner has not historically settled these awards in cash. Although other types of awards are contemplated under the LTIP, all currently outstanding awards are phantom units without distribution equivalent rights.

Generally, grants issued under the LTIP vest in increments of 25% on each grant date anniversary and do not contain any vesting conditions other than continued employment requirements.

The following table summarizes changes in our unit-based awards during the six months ended June 30, 2015 indicated, in units:

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	Six months ended June 30, 2015	
	Units	Weighted-Average Exercise Price
Outstanding at beginning of period	201,132	$ 19.85
Granted	336,613	15.78
Forfeited	(8,297)	17.24
Vested	(126,897)	18.84
Outstanding at end of period	402,551	$ 16.82

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our limited partner units at the grant date. Compensation costs related to these awards, including amortization, for the three months ended June 30, 2015 and 2014 were $0.6 million and $0.4 million, respectively, and for the six months ended June 30, 2015 and 2014 were $2.2 million and $0.8 million, respectively, which are classified as Equity compensation expense in our condensed consolidated statements of operations and the non-cash portion in partners' capital on our condensed consolidated balance sheets.

The total fair value of vested units at the time of vesting was $2.3 million and $0.8 million for the six months ended June 30, 2015 and 2014, respectively.

Equity compensation expense related to unvested awards not yet recognized at June 30, 2015 and 2014 was $6.0 million and $3.8 million, respectively, and the weighted average period over which this cost is expected to be recognized as of June 30, 2015 is approximately 3.2 years.

15. Income Taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. However, the State of Texas imposes a margin tax upon the Partnership that is assessed annually against the taxable margin apportioned to Texas. In general, taxes on our net income are borne by our unitholders through the allocation of taxable income. However, one of our subsidiaries, American Midstream Blackwater, LLC, owns a corporate consolidated tax return group which is a separate taxable entity for U.S. federal income tax and state income tax purposes. The provision for income taxes is attributable to the activities of the taxable corporate consolidated tax return group and taxable margin apportioned to Texas.

On October 2, 2014, the Partnership received a "Notice of Beginning of Administrative Proceeding" (the "NBAP") relating to the Internal Revenue Service (the "IRS") commencing an audit of the Partnership's 2012 Form 1065 federal tax return. Under IRS regulations, the Partnership was required to communicate the NBAP to all limited partners who hold less than 1% of its outstanding units ("Non-Notice Partners") within 75 days of receipt of the NBAP. The Partnership filed a Current Report on Form 8-K with the SEC on November 19, 2014, furnishing a copy of the NBAP to its Non-Notice Partners.

On June 19, 2015, the Partnership received a No Adjustments Letter (the "No Adjustments Letter") relating to the IRS audit of Partnership's 2012 Form 1065 federal tax return. There were no adjustments proposed by the IRS for the Partnership's 2012 Form 1065 federal tax return. The Partnership filed a Current Report on Form 8-K with the SEC on June 24, 2015, furnishing a copy of the No Adjustments Letter to its Non-Notice Partners.

Income tax expense for the three and six months ended June 30, 2015 was $0.3 million and $0.5 million, respectively, resulting in an effective tax rate of 18.8% and 68.3%, respectively. For the three and six months ended June 30, 2014, income tax expense was $0.1 million and $0.1 million, respectively, resulting in an effective tax rate of 15.8% and 34.6%, respectively.

The effective tax rates for the three and six months ended June 30, 2015 and June 30, 2014, differ from the statutory rate primarily due to the portion of the Partnership's income and loss that is not subject to U. S. federal income taxes, as well as transactions between the Partnership and its taxable subsidiary that generate tax deductions for the taxable subsidiary, which are eliminated in the consolidation of Net income (loss) before income tax (expense) benefit.

16. Commitments and Contingencies

Legal proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainty, our management believes that the resolution of any of our pending proceedings will not have a material adverse effect on our financial condition or results of operations.

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to natural gas pipelines, NGL and crude pipelines and operations, as well as terminal operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Regulatory matters

On December 11, 2014, American Midstream (Midla), LLC ("Midla"), a subsidiary of the Partnership, filed a Stipulation and Agreement (the "Midla Agreement") which resolved all of the outstanding issues between Midla and its customers regarding its interstate pipeline that traverses Louisiana and Mississippi owned and operated by Midla. The parties involved reached agreement in order to provide continued service to Midla’s customers while addressing safety concerns with the existing pipeline.

On April 16, 2015, the FERC approved the Midla Agreement between Midla and its customers allowing Midla to retire the existing 1920s vintage pipeline and replace the existing natural gas service with a new pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the “Midla-Natchez Line”) to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service.

On June 29, 2015, the Partnership filed with the FERC for authorization to construct the Midla-Natchez pipeline. The Midla-Natchez pipeline will replace the Midla pipeline with a new, 12-inch pipeline extending approximately 50 miles from Winnsboro, Louisiana to Natchez, Mississippi. Subject to FERC approval, construction is expected to commence in the first half of 2016 with service beginning in late 2016. Under the Midla Agreement, Midla will execute long-term agreements to recover its investment in the Midla-Natchez Line.

17. Related-Party Transactions

Employees of our General Partner are assigned to work for us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our General Partner to the Partnership, which, in turn, charges the appropriate subsidiary. Our General Partner does not record any profit or margin for the administrative and operational services charged to us. During the three and six months ended June 30, 2015, administrative and operational services expenses of $7.4 million and $15.0 million, respectively, were charged to us by our General Partner. During the three and six months ended June 30, 2014, administrative and operational services expenses of $5.1 million and $10.1 million, respectively, were charged to us by our General Partner. For the three and six months ended June 30, 2015, our General Partner incurred approximately $0.5 million and $0.9 million, respectively, of costs primarily associated with certain business development activities. For the three and six months ended June 30, 2014, our General Partner incurred costs primarily associated with certain business development activities in amounts equal to approximately $0.2 million and $0.7 million, respectively.

For the three and six months ended June 30, 2015, the Partnership and an affiliate of HPIP entered into arrangements under which the affiliate reimbursed the Partnership for right-of-ways purchased on the affiliate's behalf for approximately $1.1 million and $3.9 million, respectively.

During the second quarter of 2014, the Partnership and an affiliate of its General Partner entered into a Management Service Fee arrangement under which the affiliate pays a monthly fee to reimburse the Partnership for administrative expenses incurred on the affiliates' behalf. During the three and six months ended June 30, 2015, the Partnership recognized $0.4 million and $0.9 million, in management fee income, respectively, and $0.2 million during the three and six months ended June 30, 2014 that has been recorded as a reduction to Selling, general and administrative expenses.

18. Reporting Segments

Our operations are located in the United States and are organized into three reporting segments: i) Gathering and Processing, ii) Transmission and iii) Terminals.

Gathering and Processing

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Our Gathering and Processing segment provides “wellhead-to-market” services to producers of natural gas and oil, which include transporting raw natural gas from the wellhead through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems.

Transmission

Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include local distribution companies, utilities and industrial, commercial and power generation customers.

Terminals

Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products.

These segments are monitored separately by management for performance and are consistent with the Partnership's internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is the performance measure utilized by management to monitor the business of each segment.

The following tables set forth our segment information for the three and six months ended June 30, 2015 and 2014 (in thousands):

	Three months ended June 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$50,439	$12,423	$4,336	$67,198
Gain (loss) on commodity derivatives, net	311	—	—	311
Total revenue	50,750	12,423	4,336	67,509
Operating expenses:				
Purchases of natural gas, NGL's and condensate	30,272	3,062	—	33,334
Direct operating expenses	9,130	3,253	1,584	13,967
Selling, general and administrative expenses				5,571
Equity compensation expense				550
Depreciation, amortization and accretion expense				9,250
Total operating expenses				62,672
Gain (loss) on sale of assets, net				(2,970)
Interest expense				(3,556)
Earnings in unconsolidated affiliates				4
Income tax benefit (expense)				(317)
Gain (loss) from discontinued operations, net of tax				(31)
Net income (loss)				(2,033)
Less: Net income (loss) attributable to noncontrolling interests				32
Net income (loss) attributable to the Partnership				$(2,065)

Segment gross margin (a)	$20,219	$9,333	$2,752	$32,304

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	Three months ended June 30, 2014			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$50,015	$23,960	$3,898	$77,873
Gain (loss) on commodity derivatives, net	(193)	—	—	(193)
Total revenue	49,822	23,960	3,898	77,680
Operating expenses:				
Purchases of natural gas, NGL's and condensate	39,238	14,580	—	53,818
Direct operating expenses	5,746	3,736	1,562	11,044
Selling, general and administrative expenses				5,637
Equity compensation expense				435
Depreciation, amortization and accretion expense				6,012
Total operating expenses				76,946
Interest expense				(1,680)
Income tax benefit (expense)				(149)
Gain (loss) from discontinued operations, net of tax				(506)
Net income (loss)				(1,601)
Less: Net income (loss) attributable to noncontrolling interests				66
Net income (loss) attributable to the Partnership				$(1,667)
Segment gross margin (a)	$10,481	$9,350	$2,336	$22,167

	Six months ended June 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$98,888	$24,171	$8,601	$131,660
Gain (loss) on commodity derivatives, net	458	—	—	458
Total revenue	99,346	24,171	8,601	132,118
Operating expenses:				
Purchases of natural gas, NGL's and condensate	57,590	4,721	—	62,311
Direct operating expenses	18,223	6,432	3,179	27,834
Selling, general and administrative expenses				12,506
Equity compensation expense				2,248
Depreciation, amortization and accretion expense				18,939
Total operating expenses				123,838
Gain (loss) on sale of assets, net				(2,978)
Interest expense				(6,166)
Earnings in unconsolidated affiliates				171
Income tax benefit (expense)				(473)
Gain (loss) from discontinued operations, net of tax				(26)
Net income (loss)				(1,192)
Less: Net income (loss) attributable to noncontrolling interests				46
Net income (loss) attributable to the Partnership				$(1,238)

Segment gross margin (a)	$41,265	$19,394	$5,422	$66,081

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	Six months ended June 30, 2014			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$101,641	$49,088	$7,512	$158,241
Gain (loss) on commodity derivatives, net	(323)	—	—	(323)
Total revenue	101,318	49,088	7,512	157,918
Operating expenses:				
Purchases of natural gas, NGL's and condensate	80,359	28,680	—	109,039
Direct operating expenses	9,914	6,854	3,237	20,005
Selling, general and administrative expenses				11,230
Equity compensation expense				795
Depreciation, amortization and accretion expense				13,644
Total operating expenses				154,713
Gain (loss) on sale of assets, net				(21)
Interest expense				(3,583)
Income tax benefit (expense)				(138)
Gain (loss) from discontinued operations, net of tax				(556)
Net income (loss)				(1,093)
Less: Net income (loss) attributable to noncontrolling interests				174
Net income (loss) attributable to the Partnership				$(1,267)
Segment gross margin (a)	$20,610	$20,363	$4,275	$45,248

	June 30, 2015	December 31, 2014
Segment assets:		
Gathering and Processing	$684,359	$686,395
Transmission	128,291	132,767
Terminals	83,766	71,180
Other (b)	40,231	26,302
Total assets	$936,647	$916,644

(a) Segment gross margin for our Gathering and Processing segment consists of revenue and realized gains or (losses) on commodity derivatives less purchases of natural gas, NGLs and condensate and revenue from construction, operating and maintenance agreements (“COMA”). Segment gross margin for our Transmission segment consists of revenue, less purchases of natural gas and COMA. Segment gross margin for our Terminals segment consists of revenue, less direct operating expenses. Gross margin consists of the sum of the segment gross margin amounts for each of these segments. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Other assets not allocable to segments consist of investment in unconsolidated affiliates, corporate leasehold improvements, and other assets.

19. Subsequent Events

GP Contribution

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In connection with the issuance of the Series A-2 Units discussed in Note 13, the General Partner exercised its right to maintain its general partner interest at 1.3%. As a result, we received proceeds of $0.4 million from our General Partner as consideration for 21,975 additional notional general partner units in July of 2015.

Distribution

On July 23, 2015, we announced a distribution of $0.4725 per unit for the quarter ended June 30, 2015, or $1.89 per unit on an annualized basis, payable on August 14, 2015 to unitholders of record on August 5, 2015.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report and the audited consolidated financial statements and notes thereto and management's discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 2014 included in our Annual Report on Form 10-K ("Annual Report") that was filed with the Securities and Exchange Commission ("SEC") on March 10, 2015. This discussion contains forward-looking statements that reflect management's current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption "Cautionary Statement Regarding Forward-Looking Statements."

Cautionary Statement About Forward-Looking Statements

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements". You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Examples of these risks and uncertainties, many of which are beyond our control, include, but are not limited to, the following:

- our ability to maintain compliance with financial covenants and ratios under our credit facility, which include a maximum leverage ratio on a quarterly basis, could adversely affect our operations and our ability to pay distributions to our unitholders;
- our ability to access capital to fund growth, including, but not limited to, access to the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the timing and extent of changes in crude oil, natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;
- the level and success of crude oil and natural gas drilling around our assets and our success in connecting crude oil and natural gas supplies to our gathering and processing systems;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including, but not limited to, the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- weather and other natural phenomena, including, but not limited to, their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- industry changes, including, but not limited to, the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the demand for NGL products by the petrochemical, refining or other industries;

- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects and the successful integration and future performance of such assets;
- our ability to hire as well as retain qualified personnel to execute our business strategy;
- volatility in the price of our common units;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- our ability to timely and successfully integrate our current and future acquisitions, including, but not limited to, the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance; and
- general economic, market and business conditions.

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Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report will prove to be accurate. Some of these and additional risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in Part II, Item 1A of this Quarterly Report under the caption “Risk Factors”, Part I, Item 1A of our Annual Report under the caption "Risk Factors" and elsewhere in this Quarterly Report and our Annual Report. The forward-looking statements in this report speak as of the filing date of this report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

Overview

We are a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We are engaged in the business of gathering, treating, processing, and transporting natural gas, fractionating NGLs, transporting oil and storing specialty chemical products through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, four marine terminal sites, three interstate pipelines, five intrastate pipelines and one oil pipeline. We also own a 66.7% non-operating interest in MPOG, a crude oil gathering and processing system, a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant, as well as a 46% non-operating interest in Mesquite, an off-spec condensate fractionation project. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links producers of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate approximately 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.7 million barrels of storage capacity across four marine terminal sites.

Financial highlights for the three months ended June 30, 2015, include the following:

- Gross margin increased to $32.3 million, or an increase of 45.5%, compared to the same period in 2014 primarily due to the Costar and Lavaca acquisitions;

- Adjusted EBITDA increased to $14.5 million, or an increase of 113.2%, compared to the same period in 2014 primarily due to the Costar and Lavaca acquisitions;

- We distributed $10.8 million to our Limited Partner common unitholders, or $0.4725 per unit; and

- On June 30, 2015, we issued additional Series A-2 Convertible Preferred Units to Magnolia Infrastructure Partners, LLC (an affiliate of HPIP) in a private placement for $25.0 million in aggregate proceeds.

Operational highlights for the three months ended June 30, 2015, include the following:

- The percentage of gross margin generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts increased to 82.7% compared to 78.8% for the same period in 2014;

- Average gross NGL production totaled 331.1 Mgal/d representing a 293.9 Mgal/d increase compared to the same period in 2014;

- Average condensate production totaled 95.8 Mgal/d, representing a 52.8 Mgal/d increase compared to the same period in 2014;

- Throughput attributable to the Partnership totaled 1,031.2 MMcf/d, remaining relatively consistent to the same period in 2014; and

- Storage utilization decreased to 86.9% compared to 97.7% for the same period in 2014, as a result of an increase in total available capacity at our Harvey terminal, bringing total storage capacity at Harvey to approximately 435,000 barrels.

Recent Developments

Series A-2 Convertible Preferred Units

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On March 30, 2015 and June 30, 2015, we entered into two Series A-2 Convertible Preferred Unit Purchase Agreements with Magnolia Infrastructure Partners, LLC (an affiliate of HPIP) pursuant to which the Partnership issued, in separate private placements, Series A-2 Units for approximately $45.0 million in aggregate proceeds. The Series A-2 Units will participate in distributions of the Partnership along with common units in a manner identical to the existing Series A Units (such previously existing Series A Units now referred to as the "Series A-1 Units" and, together with the Series A-2 Units, the "Series A Units"), with such distributions being made in cash or with paid-in-kind Series A Units at the election of the board of directors of our General Partner. The board of directors of our General Partner has, to date, elected to pay Series A distributions using paid-in-kind Series A Units.

On July 27, 2015, we entered into the Fifth Amendment (the “Fifth Amendment”) to our partnership agreement. The Fifth Amendment grants us the right (the “Call Right”) to require the holders of the Series A-2 Units (the “Series A-2 Holders”) to sell, assign and transfer all or a portion of the then outstanding Series A-2 Units to us for a purchase price of $17.50 per Series A-2 Unit (subject to appropriate adjustment for any equity distribution, subdivision or combination of equity interests in the Partnership). We may exercise the Call Right at any time after January 1, 2016, in connection with our or our affiliate’s acquisition of assets or equity from ArcLight Energy Partners Fund V, L.P., or one of its affiliates, for a purchase price in excess of $100 million. We may not exercise the Call Right with respect to any Series A-2 Units that a Series A-2 Holder has elected to convert into common units on or prior to the date we have provided notice of our intent to exercise the Call Right, and may not exercise the Call Right if doing so would result in a default under any of our or our affiliates’ financing agreements or obligations.

Changes in Commodity Prices

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.43 per barrel to a low of $47.12 per barrel from April 1, 2015 through August 1, 2015. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.07 per MMBtu to a low of $2.48 per MMBtu from April 1, 2015 through August 1, 2015.

Fluctuations in energy prices, like the recent declines in commodity prices of oil and natural gas, can also greatly affect the development of new oil and natural gas reserves. Further declines in commodity prices of oil and natural gas could have a negative impact on exploration, development and production activity, and, if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, oil and NGLs and thus, cannot predict the ultimate impact of commodity prices on our operations. If commodity prices continue to trend lower as they did in the latter part of 2014 and the first half of 2015, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants and ratios under our credit facility, which include a maximum leverage ratio on a quarterly basis. Reduced profitability could adversely affect our operations, our ability to pay distributions to our unitholders, and may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

Republic Midstream Crude Oil System

On August 5, 2014, we executed our right-of-first-offer to acquire a 50 percent interest in Republic Midstream, LLC (“Republic Midstream”) from an affiliate of ArcLight Capital Partners, LLC ("ArcLight"), which controls 95% of our General Partner. Republic Midstream, an ArcLight portfolio company, executed an agreement with Penn Virginia Corporation ("Penn Virginia") in July 2014 to construct and operate a crude oil gathering system, central delivery terminal complex, and an intermediate takeaway pipeline to serve Penn Virginia’s acreage position in the Eagle Ford Shale. As a result of weather related construction delays, the Republic System is expected to commence operations in late 2015. In accordance with the terms of the previously mentioned agreement, we expect to exercise our right to acquire 50 percent of Republic Midstream in 2016.

We currently provide construction, operations, and general management services for Republic Midstream and we expect to continue to provide such services should we exercise our option described above.

Midla Regulatory Matters

On April 16, 2015, the FERC approved the Midla Agreement between Midla and its customers allowing Midla to retire the existing 1920s vintage pipeline and replace the existing natural gas service with a new pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the “Midla-Natchez Line”) to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service.

On June 29, 2015, the Partnership filed with the FERC for authorization to construct the Midla-Natchez pipeline. The Midla-Natchez pipeline will replace the Midla pipeline with a new, 12-inch pipeline extending approximately 50 miles from Winnsboro,

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Louisiana to Natchez, Mississippi. Subject to FERC approval, construction is expected to commence in the first half of 2016 with service beginning in late 2016. Under the Midla Agreement, Midla will execute long-term agreements to recover its investment in the Midla-Natchez Line.

Gonzales County Full-Well-Stream Gathering System

On August 4, 2014, the board of directors of our General Partner approved the exercise of our right-of-first-offer to acquire the Gonzales County full-well-stream gathering and treating and saltwater disposal system in the Eagle Ford Shale that is being developed by an affiliate of our General Partner. Midstream services would be provided to the producer customer under a long-term, fee-based agreement. The producer customer on the system announced its intention to cease drilling activities in areas served by the system. As such, the Partnership does not anticipate drop-down of the system in 2015 and will continue to evaluate timing of a drop-down with the General Partner.

High Point Lateral

In February 2015, the Partnership executed a 15-year, fee-based agreement to construct a 15-mile extension of the High Point system to serve an existing refinery customer in southeast Louisiana. Construction is expected to commence later this year with service expected to begin in early 2016.

Subsequent Events

GP Contribution

In connection with the issuance of the Series A-2 Units discussed in Note 13, we received proceeds of $0.4 million from our General Partner as consideration for 21,975 additional notional general partner units in July of 2015.

Distribution

On July 23, 2015, we announced a distribution of $0.4725 per unit for the quarter ended June 30, 2015, or $1.89 per unit on an annualized basis, payable on August 14, 2015 to unitholders of record on August 5, 2015.

Our Operations

We manage our business and analyze and report our results of operations through three business segments:

- Gathering and Processing. Our Gathering and Processing segment provides “wellhead-to-market” services to producers of natural gas and oil, which include transporting raw natural gas from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas as well as NGLs to various markets and pipeline systems.

- Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include local distribution companies (“LDCs”), utilities and industrial, commercial and power generation customers.

- Terminals. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including various petroleum products, distillates, chemicals and agricultural products.

Gathering and Processing Segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas we gather, process and fractionate, the commercial terms in our current contract portfolio and natural gas, NGL and condensate prices. We gather and process gas primarily pursuant to the following arrangements:

- Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed cash fee for gathering and processing and transporting natural gas.

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- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas and off-spec condensate from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas or off-spec condensate at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas or off-spec condensate, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

- Percent-of-Proceeds Arrangements (“POP”). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, such as under our Toca contract, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas, such as the contracts for our interest in the Burns Point Plant. Our POP arrangements also often contain a fee-based component.

We account for our 50% interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our condensed consolidated statement of operations, our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.

We account for our 92.2% undivided interest in the Chatom System pursuant to Accounting Standards Codification ASC No. 810-10-65-1, Noncontrolling Interests. Under this method, revenues, expenses, gains, losses, net income or loss, and other comprehensive income are reported in our condensed consolidated financial statements at the consolidated amounts, which include the amounts attributable to the partners and the noncontrolling interests. Our condensed consolidated income statement shall separately present net income attributable to the partners and the noncontrolling interests.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in throughput volumes from producers and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows but minimal, if any, upside in higher commodity-price environments. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. Please read the information set forth in Part I, Item 3 of this Quarterly Report under the caption “ — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.”

Transmission Segment

Results of operations from our Transmission segment are determined by capacity reservation fees from firm transportation contracts and the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

- Firm Transportation Arrangements. Our obligation to provide firm transportation service means that we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us.

- Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped.

- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

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Terminals Segment

Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products. We generally receive fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when products are either received or delivered to customers for throughput volumes in excess of those stipulated in the associated storage contract, along with other operational charges associated with ancillary services provided, such as excess throughput, truck weighing, etc. Our firm storage contracts are typically multi-year contracts, with renewal options.

Contract Mix

For the three months ended June 30, 2015 and 2014, $26.7 million and $17.5 million, or 82.7% and 78.8%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts, which have little or no direct commodity price exposure. Set forth below is a table summarizing our average contract mix relative to segment gross margin for the three months ended June 30, 2015 and 2014 (in millions):

	For the Three Months Ended June 30, 2015			For the Three Months Ended June 30, 2014		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gathering and Processing						
Fee-based	$9.2	45.8	%	$4.4	41.9	%
Fixed margin	5.4	26.5	%	1.4	13.3	%
Percent-of-proceeds	5.6	27.7	%	4.7	44.8	%
Total	$20.2	100.0	%	$10.5	100.0	%
Transmission						
Firm transportation	$2.9	30.9	%	$2.4	25.3	%
Interruptible transportation	6.4	69.1	%	7.0	74.7	%
Total	$9.3	100.0	%	$9.4	100.0	%
Terminals						
Firm storage	$2.8	100.0	%	$2.3	100.0	%
Total	$2.8	100.0	%	$2.3	100.0	%

For the six months ended June 30, 2015 and 2014, $55.5 million and $34.2 million, or 84.0% and 75.5%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts. Set forth below is a table summarizing our average contract mix relative to segment gross margin for the six months ended June 30, 2015 and 2014 (in millions):

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	For the Six Months Ended June 30, 2015		For the Six Months Ended June 30, 2014	
	Segment Gross Margin	Percent of Segment Gross Margin	Segment Gross Margin	Percent of Segment Gross Margin
Gathering and Processing				
Fee-based	$19.1	46.2 %	$8.0	38.9 %
Fixed margin	11.6	28.2 %	1.5	7.5 %
Percent-of-proceeds	10.6	25.6 %	11.1	53.6 %
Total	$41.3	100.0 %	$20.6	100.0 %
Transmission				
Firm transportation	$6.0	31.0 %	$5.5	27.2 %
Interruptible transportation	13.4	69.0 %	14.9	72.8 %
Total	$19.4	100.0 %	$20.4	100.0 %
Terminals				
Firm storage	$5.4	100.0 %	$4.3	100.0 %
Total	$5.4	100.0 %	$4.3	100.0 %

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include throughput volumes, gross margin and direct operating expenses on a segment basis, and adjusted EBITDA on a company-wide basis.

Throughput Volumes

In our Gathering and Processing segment, we must continually obtain new supplies of natural gas, NGLs and condensate to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas, NGLs and condensate and obtain new supplies is impacted by i) the level of work-overs or recompletions of existing connected wells and successful drilling activity of our significant producers in areas currently dedicated to or near our gathering systems, ii) our ability to compete for volumes from successful new wells in the areas in which we operate, iii) our ability to obtain natural gas, NGLs and condensate that has been released from other commitments and iv) the volume of natural gas, NGLs and condensate that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

In our Transmission segment, the majority of our segment gross margin is generated by firm and interruptible capacity reservation fees from throughput volumes on our interstate and intrastate pipelines. Substantially all Transmission segment gross margin is generated under contracts with shippers, including producers, industrial companies, LDCs and marketers, for firm and interruptible natural gas transportation on our pipelines. We routinely monitor natural gas market activities in the areas served by our transmission systems to pursue new shipper opportunities.

In our Terminals segment, throughput fees are charged to our customers when their products are either received or disbursed, along with other operational charges associated with ancillary services, such as excess throughput, truck weighing, and related services.

Gross Margin and Segment Gross Margin

Gross margin and segment gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as revenue generated from gathering and processing operations and realized gains or (losses) on commodity derivatives less the cost of natural gas, NGLs and condensate purchased and revenue from construction, operating and maintenance agreements (“COMA”). Revenue includes revenue generated from fixed fees associated with the gathering and treating of natural gas and from the sale of natural gas, NGLs and condensate resulting from gathering and processing activities under fixed-margin and POP arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to POP arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

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We define segment gross margin in our Transmission segment as revenue generated from firm and interruptible transportation agreements and fixed-margin arrangements, plus other related fees, less the cost of natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.
We define segment gross margin in our Terminals segment as revenue generated from fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers less direct operating expense which includes direct labor, general materials and supplies and direct overhead.

We define gross margin as the sum of our segment gross margin for our Gathering and Processing, Transmission and Terminals segments. The GAAP measure most comparable to gross margin is net income (loss) attributable to the Partnership.

Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses without sacrificing safety or the environment. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities, lost and unaccounted for gas, and contract services comprise the most significant portion of our operating expenses. These expenses are relatively stable and largely independent of throughput volumes through our systems but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA

Adjusted EBITDA is a measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unit holders and General Partner;

- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and

- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

We define adjusted EBITDA as net income, plus interest expense, income tax expense, depreciation expense, certain non-cash charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts, cash distributions in excess of earnings from unconsolidated affiliate and selected charges that are unusual or nonrecurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, amortization of commodity put purchase costs, and selected gains that are unusual or nonrecurring. The GAAP measure most directly comparable to adjusted EBITDA is net income (loss) attributable to the Partnership.

Note About Non-GAAP Financial Measures

Gross margin and adjusted EBITDA are non-GAAP financial measures. Each has important limitations as an analytical tool because it excludes some, but not all, items that affect the most directly comparable GAAP financial measures. Management compensates for the limitations of these non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

You should not consider any of gross margin or adjusted EBITDA in isolation or as a substitute for or more meaningful than analysis of our results as reported under GAAP. Gross margin and adjusted EBITDA may be defined differently by other companies in our industry.

The following tables reconcile the non-GAAP financial measures of gross margin and adjusted EBITDA to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for the three and six months ended June 30, 2015 and 2014 (in thousands):

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	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership:				
Gathering and processing segment gross margin	$20,219	$10,481	$41,265	$20,610
Transmission segment gross margin	9,333	9,350	19,394	20,363
Terminals segment gross margin	2,752	2,336	5,422	4,275
Total Gross Margin	32,304	22,167	66,081	45,248
Plus:				
Gain (loss) on commodity derivatives, net	311	(193)	458	(323)
Earnings in unconsolidated affiliates	4	—	171	—
Less:				
Direct operating expenses (a)	12,383	9,482	24,655	16,768
Selling, general and administrative expenses	5,571	5,637	12,506	11,230
Equity compensation expense	550	435	2,248	795
Depreciation, amortization and accretion expense	9,250	6,012	18,939	13,644
(Gain) loss on sale of assets, net	2,970	—	2,978	21
Interest expense	3,556	1,680	6,166	3,583
Other, net (b)	24	(326)	(89)	(717)
Income tax expense (benefit)	317	149	473	138
Gain (loss) from discontinued operations, net of tax	31	506	26	556
Net income (loss) attributable to noncontrolling interest	32	66	46	174
Net income (loss) attributable to the Partnership	$(2,065)	$(1,667)	$(1,238)	$(1,267)

(a) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $9.1 million and $5.7 million, respectively, and Transmission segment direct operating expenses of $3.3 million and $3.7 million, respectively, for the three months ended June 30, 2015 and 2014. Direct operating expenses related to our Terminals segment of $1.6 million and $1.6 million, respectively, for the three months ended June 30, 2015 and 2014 are included within the calculation of Terminals segment gross margin.

Direct operating expenses includes Gathering and Processing segment direct operating expenses of $18.2 million and $9.9 million, respectively, and Transmission segment direct operating of $6.4 million and $6.9 million, respectively, for the six months ended June 30, 2015 and 2014. Direct operating expenses related to our Terminals segment of $3.2 million and $3.2 million, respectively, for the six months ended June 30, 2015 and 2014 are included within the calculation of Terminals segment gross margin.

(b) Other, net includes realized gain (loss) on commodity derivatives of $0.3 million and $(0.1) million, respectively, and COMA income of $0.2 million and $0.2 million, respectively, for the three months ended June 30, 2015 and 2014.

Other, net includes realized gain (loss) on commodity derivatives of $0.4 million and $(0.2) million, respectively, and COMA income of $0.5 million and $0.5 million, respectively, for the six months ended June 30, 2015 and 2014, respectively.

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	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Reconciliation of Adjusted EBITDA to Net income (loss) attributable to the Partnership				
Net income (loss) attributable to the Partnership	$(2,065)	$(1,667)	$(1,238)	$(1,267)
Add:				
Depreciation, amortization and accretion expense	9,250	6,012	18,939	13,644
Interest expense	3,360	1,351	5,744	2,844
Debt issuance costs	46	11	276	154
Unrealized (gain) loss on derivatives, net	(157)	75	(213)	113
Non-cash equity compensation expense	550	435	2,248	795
Transaction expenses	—	226	43	1,038
Income tax expense (benefit)	297	(135)	457	(161)
Loss on impairment of noncurrent assets held for sale	—	673	—	673
Return of capital from unconsolidated affiliate	496	—	1,329	—
Deduct:				
COMA income	229	246	481	534
OPEB plan net periodic benefit	3	12	6	23
Gain (loss) on sale of assets, net	(2,970)	(63)	(2,978)	(106)
Adjusted EBITDA	$14,515	$6,786	$30,076	$17,382

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed in Part II, Item 7 of our Annual Report under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations — General Trends and Outlook".

Results of Operations — Combined Overview

Gross margin increased by $10.1 million, or 45.5%, for the three months ended June 30, 2015 and increased by $20.8 million, or 46.0%, for the six months ended June 30, 2015 as compared to the same periods in 2014. For the three months ended June 30, 2015, our gross margin increased largely as a result of incremental gross margin of $9.2 million associated with the gathering and processing systems obtained through the Costar Acquisition, and higher gross margin from the Lavaca System of $1.5 million. For the six months ended June 30, 2015, the increase in gross margin was largely as a result of incremental gross margin of $18.5 million associated with the gathering and processing systems obtained through the Costar Acquisition, and higher gross margin from the Lavaca System of $5.0 million.

For the three months ended June 30, 2015, adjusted EBITDA increased $7.7 million, or 113.2%, compared to the same period in 2014. The increase is primarily related to incremental gross margin in the Gathering and Processing segment from the Costar Acquisition mentioned above. For the six months ended June 30, 2015, adjusted EBITDA increased $12.7 million, or 73.0%, compared to the same period in 2014. The increase is primarily related to incremental gross margin in the Gathering and Processing segment from the Costar Acquisition mentioned above, as well as the acquisition of the Lavaca System, partially offset by higher direct operating expenses associated with the Costar and Lavaca System acquisitions and lower gross margin related to certain legacy assets within the Gathering and Processing segment.

We distributed $21.5 million to holders of our Limited Partner common units, or $0.9450 per unit, during the six months ended June 30, 2015, including a distribution with respect to the three months ended December 31, 2014. The distribution of $0.4725 per unit represents an increase of 2.2%, period over period.

The following table and discussion presents certain of our historical condensed consolidated financial data for the periods indicated. The results of operations by segment are discussed in further detail following this combined overview (in thousands):

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	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Statement of Operations Data:				
Revenue	$67,198	$77,873	$131,660	$158,241
Gain (loss) on commodity derivatives, net	311	(193)	458	(323)
Total revenue	67,509	77,680	132,118	157,918
Operating expenses:				
Purchases of natural gas, NGLs and condensate	33,334	53,818	62,311	109,039
Direct operating expenses	13,967	11,044	27,834	20,005
Selling, general and administrative expenses	5,571	5,637	12,506	11,230
Equity compensation expense (a)	550	435	2,248	795
Depreciation, amortization and accretion expense	9,250	6,012	18,939	13,644
Total operating expenses	62,672	76,946	123,838	154,713
Gain (loss) on sale of assets, net	(2,970)	—	(2,978)	(21)
Operating income (loss)	1,867	734	5,302	3,184
Other income (expense):				
Interest expense	(3,556)	(1,680)	(6,166)	(3,583)
Earnings in unconsolidated affiliates	4	—	171	—
Net income (loss) before income tax (expense) benefit	(1,685)	(946)	(693)	(399)
Income tax (expense) benefit	(317)	(149)	(473)	(138)
Net income (loss) from continuing operations	(2,002)	(1,095)	(1,166)	(537)
Income (loss) from discontinued operations, net of tax	(31)	(506)	(26)	(556)
Net income (loss)	(2,033)	(1,601)	(1,192)	(1,093)
Net income (loss) attributable to noncontrolling interests	32	66	46	174
Net income (loss) attributable to the Partnership	$(2,065)	$(1,667)	$(1,238)	$(1,267)
Other Financial Data:				
Gross margin (b)	$32,304	$22,167	$66,081	$45,248
Adjusted EBITDA (b)	$14,515	$6,786	$30,076	$17,382

(a) Represents non-cash costs related to our Long-Term Incentive Plan.

(b) For definitions of gross margin and adjusted EBITDA and reconciliations to their most directly comparable financial measure calculated and presented in accordance with GAAP, and a discussion of how we use gross margin and adjusted EBITDA to evaluate our operating performance, please read the information in this Item under the caption "— How We Evaluate Our Operations."

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Total Revenue. Our total revenue for the three months ended June 30, 2015 was $67.5 million compared to $77.7 million for the three months ended June 30, 2014. This decrease of $10.2 million was primarily due to a decrease in natural gas revenues of $27.0 million as a result of:

- lower realized natural gas prices of $2.75/Mcf, which is a decrease of $2.40/Mcf, or 46.6% period over period,
- lower natural gas sales volumes as a result of converting certain fixed-margin contracts in our transmission segment to firm or interruptible transportation contracts, and
- lower volumes associated with our elective processing agreement.

The decrease in natural gas revenues was partially offset by:

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- an increase in NGL revenues of $10.1 million due to higher gross NGL production of 293.9 Mgal/d from our Gathering and Processing segment; partially offset by lower realized NGL prices of $0.64/gal, which was a decrease of $0.33/gal period over period,
- an increase in fee-based revenues of $5.1 million primarily due to higher average throughput in our Gathering and Processing segment of 67.8 MMcf/d, or 25.5%,
- an increase in Terminals segment revenue of $0.4 million as a result of incremental storage utilization from acquiring new customers and contractual storage rate escalations, and
- increases in gain (loss) on commodity derivatives, net of $0.5 million period over period.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended June 30, 2015 were $33.3 million compared to $53.8 million for the three months ended June 30, 2014. This decrease of $20.5 million was due to lower natural gas purchases of $27.1 million related to lower volumes and natural gas prices associated with our elective processing arrangements in our Gathering and Processing segment; as well as the conversion of certain fixed-margin contracts to interruptible transportation contracts in our Transmission segment as mentioned above.

This decrease was partially offset by incremental NGL and condensate purchases of $9.0 million primarily associated with the gathering and processing systems acquired in the Costar Acquisition.

Gross Margin. Gross margin for the three months ended June 30, 2015 was $32.3 million compared to $22.2 million for the three months ended June 30, 2014. This increase of $10.1 million was primarily due to an increase in gross margin in our Gathering and Processing segment of $9.7 million, as a result of higher NGL and condensate production of 293.9 Mgal/d and 52.8 Mgal/d, respectively, and higher throughput volumes of 67.8 MMcf/d.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2015 were $14.0 million compared to $11.0 million in the three months ended June 30, 2014. This increase of $3.0 million was primarily due to $4.3 million of incremental operating costs associated with the gathering and processing systems acquired in the Costar Acquisition; offset by the timing of activities related to our integrity management and plant maintenance programs.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the three months ended June 30, 2015 were $5.6 million, which was consistent with the $5.6 million for the three months ended June 30, 2014.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended June 30, 2015 was $9.3 million compared to $6.0 million for the three months ended June 30, 2014. This increase of $3.3 million was due to incremental depreciation of fixed assets and amortization of certain intangible assets associated with the Costar Acquisition, and the continuing development of the Lavaca System and Harvey terminals.

Interest Expense. Interest expense for the three months ended June 30, 2015 was $3.6 million compared to $1.7 million for the three months ended June 30, 2014. This increase of $1.9 million was primarily due to higher outstanding borrowings as a result of the Costar Acquisition and funding our capital growth projects during the current period.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Total Revenue. Our total revenue for the six months ended June 30, 2015 was $132.1 million compared to $157.9 million for the six months ended June 30, 2014. This decrease of $25.8 million was primarily due to a decrease in natural gas revenues of $57.3 million as a result of:

- lower realized natural gas prices of $3.08/Mcf, which is a decrease of $2.32/Mcf, or 43.0% period over period,
- converting fixed-margin contracts in our transmission segment to firm or interruptible transportation contracts, and
- lower volumes associated with our elective processing arrangements.

The decrease in natural gas revenues was partially offset by:

- an increase in NGL revenues of $15.9 million as a result of higher gross NGL production of 263.7 Mgal/d from our Gathering and Processing segment, offset by lower realized NGL prices of $0.63/gal, which is a decrease of $0.39/gal period over period,
- an increase in fee-based revenue of $11.1 million primarily due to increased average throughput in our Gathering and Processing segment of 75.6 MMcf/day, or 27.5%,
- an increase in the Terminals segment revenue of $1.1 million as a result of increased storage utilization from acquiring new customers and contractual storage rate escalations, and

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• increases in gain (loss) on commodity derivatives, net of $0.8 million period over period.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the six months ended June 30, 2015 were $62.3 million compared to $109.0 million for the six months ended June 30, 2014. This decrease of $46.7 million was due to lower natural gas purchases of $57.8 million primarily as a result of lower natural gas prices and lower natural gas volumes related to our elective processing arrangements in our Gathering and Processing segment; as well as, the conversion of certain fixed-margin contracts to interruptible transportation contracts in our Transmission segment as mentioned above.

This decrease was partially offset by incremental NGL and condensate purchases of $10.9 million primarily associated with the gathering and processing systems acquired in the Costar Acquisition.

Gross Margin. Gross margin for the six months ended June 30, 2015 was $66.1 million compared to $45.2 million for the six months ended June 30, 2014. This increase of $20.9 million was primarily due to an increase in gross margin in our Gathering and Processing segment of $20.7 million as a result of higher NGL and condensate production of 263.7 Mgal/d and 55.0 Mgal/d, respectively, and higher throughput volumes of 75.6 MMcf/d. These increases were partially offset by lower gross margin in our Transmission segment of $1.0 million as a result of decreased throughput volumes.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2015 were $27.8 million compared to $20.0 million in the six months ended June 30, 2014. This increase of $7.8 million was primarily due to $7.5 million of incremental operating costs, including costs related to direct labor and benefits, associated with the gathering and processing systems acquired in the Costar Acquisition, and $1.7 million of incremental charges associated with compression rentals used at our Lavaca System.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the six months ended June 30, 2015 were $12.5 million compared to $11.2 million for the six months ended June 30, 2014. This increase of $1.3 million was primarily due to cost incurred to manage and integrate our recent acquisitions and support continuing growth.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the six months ended June 30, 2015 was $18.9 million compared to $13.6 million for the six months ended June 30, 2014. This increase of $5.3 million was due to incremental depreciation of fixed assets and amortization of certain intangible assets associated with the Costar Acquisition and the continuing development of the Lavaca System.

Interest Expense. Interest expense for the six months ended June 30, 2015 was $6.2 million compared to $3.6 million for the six months ended June 30, 2014. This increase of $2.6 million was primarily due to a higher outstanding borrowings as a result of the Costar Acquisition and funding our capital growth projects during the current year.

Results of Operations — Segment Results

Gathering and Processing Segment

The table below contains key segment performance indicators related to our Gathering and Processing segment (in thousands except operating and pricing data).

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	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$50,439	$50,015	$98,888	$101,641
Gain (loss) on commodity derivatives, net	311	(193)	458	(323)
Total revenue	50,750	49,822	99,346	101,318
Purchases of natural gas, NGLs and condensate	30,272	39,238	57,590	80,359
Direct operating expenses	9,130	5,746	18,223	9,914
Other financial data:				
Segment gross margin	$20,219	$10,481	$41,265	$20,610
Operating data:				
Average throughput (MMcf/d)	334.1	266.3	350.8	275.2
Average plant inlet volume (MMcf/d) (a) (b)	120.0	86.4	128.0	87.0
Average gross NGL production (Mgal/d) (a) (c)	331.1	37.2	301.4	37.7
Average gross condensate production (Mgal/d) (a)	95.8	43.0	97.6	42.6
Average realized prices:				
Natural gas ($/Mcf)	$2.75	$5.15	$3.08	$5.40
NGLs ($/gal)	$0.64	$0.97	$0.63	$1.02
Condensate ($/gal)	$1.13	$2.24	$1.04	$2.22

(a) Excludes volumes and gross production under our elective processing arrangements.
(b) Includes gross plant inlet volume associated with our interest in the Burns Point processing plant.
(c) Includes net NGL production associated with our interest in the Burns Point processing plant.

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Revenue. Segment total revenue for the three months ended June 30, 2015 was $50.8 million compared to $49.8 million for the three months ended June 30, 2014. This increase of $1.0 million was primarily due to higher average NGL and condensate production of 293.9 Mgal/d and 52.8 Mgal/d, respectively, and higher average throughput volumes of 67.8 MMcf/d. The increase in average throughput volumes is primarily due to incremental average throughput volumes associated with the gathering and processing systems related to the Costar Acquisition and higher throughput volumes on the Lavaca System.

The increase in average throughput and NGL and condensate production was offset by lower realized natural gas, NGL, and condensate prices of 46.6%, 34.0%, and 49.6%, respectively, and lower natural gas volumes related to our elective processing arrangements.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended June 30, 2015 were $30.3 million compared to $39.2 million for the three months ended June 30, 2014. This decrease of $8.9 million was primarily due to lower realized natural gas and NGL prices and lower natural gas volumes related to our elective processing arrangements, partially offset by incremental purchases associated with off-spec throughput volumes at the Longview System.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2015 was $20.2 million compared to $10.5 million for the three months ended June 30, 2014. This increase of $9.7 million was primarily due to incremental gross margin of $8.8 million related to the Longview, Chapel Hill, Danville, and Yellow Rose Systems and higher gross margin of $1.5 million at the Lavaca System. These increases were offset by lower NGL and condensate production at certain legacy gathering and processing systems due to a decline in plant inlet volumes.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2015 were $9.1 million compared to $5.7 million for the three months ended June 30, 2014. This increase of $3.4 million was primarily due to the incremental operating costs associated with the gathering and processing systems acquired in the Costar and Lavaca acquisitions.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Revenue. Segment total revenue for the six months ended June 30, 2015 was $99.3 million compared to $101.3 million for the six months ended June 30, 2014. This decrease of $2.0 million was primarily due to lower realized natural gas, NGL, and condensate prices of 43.0%, 38.2%, and 53.2%, respectively; offset by higher average throughput volumes of 75.6 MMcf/d, and higher average NGL and condensate production of 263.7 Mgal/d and 55.0 Mgal/d, respectively. The increase period over period in average throughput volumes is primarily due to higher throughput volumes from the Lavaca System and the incremental throughput volumes associated with the gathering and processing systems related to the Costar Acquisition.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the six months ended June 30, 2015 were $57.6 million compared to $80.4 million for the six months ended June 30, 2014. This decrease of $22.8 million was primarily due to lower purchase costs associated with natural gas and NGLs, period over period, due to lower realized natural gas and NGL prices and lower natural gas volumes associated with our elective processing arrangements. These decreases were partially offset by incremental purchases associated with off-spec throughput volumes related to the Longview System.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2015 was $41.3 million compared to $20.6 million for the six months ended June 30, 2014. This increase of $20.7 million was primarily due to incremental gross margin of $17.8 million related to the Longview, Chapel Hill, Danville, and Yellow Rose Systems and higher gross margin of $5.0 million at our Lavaca System. These increases were offset by lower NGL and condensate production at certain legacy gathering and processing systems due to a decline in plant inlet volumes.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2015 were $18.2 million compared to $9.9 million for the six months ended June 30, 2014. This increase of $8.3 million was primarily due to the incremental operating costs associated with the gathering and processing systems acquired in the Costar and Lavaca acquisitions.

Transmission Segment

The table below contains key segment performance indicators related to our Transmission segment (in thousands except operating and pricing data).

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Segment Financial and Operating Data:				
Transmission segment				
Financial data:				
Total revenue	$12,423	$23,960	$24,171	$49,088
Purchases of natural gas, NGLs and condensate	3,062	14,580	4,721	28,680
Direct operating expenses	3,253	3,736	6,432	6,854
Other financial data:				
Segment gross margin	$9,333	$9,350	$19,394	$20,363

Operating data:				
Average throughput (MMcf/d)	697.1	765.9	753.7	814.8
Average firm transportation - capacity reservation (MMcf/d)	656.7	540.4	675.9	586.1
Average interruptible transportation - throughput (MMcf/d)	415.2	477.0	430.3	499.8

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

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Revenue. Segment total revenue for the three months ended June 30, 2015 was $12.4 million compared to $24.0 million for the three months ended June 30, 2014. This decrease of $11.6 million in segment revenue was primarily due to converting certain fixed-margin arrangements to interruptible transportation agreements during the first quarter of 2015, and therefore substantially reducing the sales of natural gas throughput volumes and also the need for us to purchase such volumes.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2015 were $3.1 million compared to $14.6 million for the three months ended June 30, 2014. This decrease of $11.5 million was primarily due to converting certain fixed-margin arrangements to interruptible transportation agreements, and therefore substantially reducing our need to purchase natural gas throughput volumes.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2015 was $9.3 million compared to $9.4 million for the three months ended June 30, 2014. This decrease of $0.1 million was primarily due to lower average throughput volumes of 9.0%, period over period, as a result of producer and pipeline maintenance activities.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2015 were $3.3 million compared to $3.7 million for the three months ended June 30, 2014. This decrease of $0.4 million was primarily related to the timing of activities associated with our integrity management program.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Revenue. Segment total revenue for the six months ended June 30, 2015 was $24.2 million compared to $49.1 million for the six months ended June 30, 2014. This decrease of $24.9 million in segment revenue was primarily due to converting certain fixed-margin arrangements to interruptible transportation agreements during the first quarter of 2015.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2015 were $4.7 million compared to $28.7 million for the six months ended June 30, 2014. This decrease of $24.0 million was primarily due to converting certain fixed-margin arrangements to interruptible transportation agreements, and therefore substantially reducing our need to purchase natural gas throughput volumes.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2015 was $19.4 million compared to $20.4 million for the six months ended June 30, 2014. This decrease of $1.0 million was primarily due to lower average throughput volumes of 7.5% period over period.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2015 were $6.4 million compared to $6.9 million for the six months ended June 30, 2014. This decrease of $0.5 million was primarily related to the timing of activities associated with our integrity management program.

Terminals Segment

The table below contains key segment performance indicators related to our Terminals segment (in thousands except operating data).

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Segment Financial and Operating Data:				
Terminals segment				
Financial data:				

Total revenue	$4,336	$3,898	$8,601	$7,512
Direct operating expenses	1,584	1,562	3,179	3,237
Other financial data:				
Segment gross margin	$2,752	$2,336	$5,422	$4,275
Operating data:				
Contracted Capacity (Bbls)	1,449,067	1,236,800	1,386,567	1,213,050
Design Capacity (Bbls)	1,667,467	1,265,600	1,585,433	1,215,600
Storage utilization (a)	86.9 %	97.7 %	87.5 %	99.8 %

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(a) Excludes storage utilization associated with our discontinued operations.

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Revenue. Segment total revenue for the three months ended June 30, 2015 was $4.3 million compared to $3.9 million for the three months ended June 30, 2014. The increase of $0.4 million was primarily attributable to increases in contracted storage capacity at the Harvey and Westwego terminals and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for both the three months ended June 30, 2015 and the three months ended June 30, 2014 were approximately $1.6 million.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2015 of $2.8 million compared to $2.3 million for the three months ended June 30, 2014. The increase of $0.5 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Revenue. Segment total revenue for the six months ended June 30, 2015 was $8.6 million compared to $7.5 million for the six months ended June 30, 2014. The increase of $1.1 million was primarily attributable to increases in contracted storage capacity at the Harvey and Westwego terminals and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2015 of $3.2 million was consistent with the six months ended June 30, 2014.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2015 of $5.4 million compared to $4.3 million for the six months ended June 30, 2014. The increase of $1.1 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Liquidity and Capital Resources

Our business is capital intensive and requires significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities.

The principal sources of our liquidity at June 30, 2015, were sources of liquidity we have accessed historically, including available borrowings under our credit facility, issuance of equity in the capital markets under registration statements or through private transactions, and financial support from ArcLight, who controls our General Partner. In addition, in the future we may seek to raise capital through the issuance of equity and unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that cash generated from operating cash flows and the sources of liquidity described above will be sufficient to meet our short-term working capital requirements, medium-term maintenance capital expenditure requirements, and quarterly cash distributions for at least the next twelve months. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, additional forms of debt or equity financing. In addition, we would reduce capital expenditures, direct operating expenses and selling, general and administrative expenses, as necessary, and reduce or eliminate quarterly distributions if required to maintain ongoing operations, which is permitted under our partnership agreement.

Our liquidity for the six months ended June 30, 2015 was impacted by our issuances of 2,571,430 Series A-2 Units, the proceeds of which were used to pay down outstanding borrowings.

Changes in natural gas, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read the information provided under Part II, Item 7A of our Annual Report under the caption, "Quantitative and Qualitative Disclosures about Market Risk" and Part I, Item 3 of the Quarterly Report under the caption "Quantitative and Qualitative Disclosures about Market Risk".

The counterparties to certain of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds is determined on a counterparty by counterparty basis, and is impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Our Credit Facility

On September 5, 2014, we entered into an amended and restated credit agreement (the "Credit Agreement"), which provides for a maximum borrowing equal to $500.0 million, with the ability to further increase the borrowing capacity subject to lender approval. The Credit Agreement contains certain financial covenants, including i) the requirement that our indebtedness not exceed 4.75 times adjusted consolidated EBITDA (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted Consolidated EBITDA), and ii) a minimum interest coverage ratio test (not less than 2.50). The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $500.0 million. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

Our obligations under the Credit Agreement are secured by a first mortgage in favor of the lenders in our real property. Advances made under the Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the new credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, which is September 5, 2019.

The Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

As of June 30, 2015 our consolidated total leverage was 5.00 and our interest coverage ratio was 8.48, which were in compliance with the financial covenants required in the Credit Agreement. The maximum permitted consolidated total leverage ratio was 5.25 for the three quarters ended June 30, 2015, as result of the acquisition of Costar Midstream in October 2014 and in accordance with the provisions of the Credit Agreement regarding permitted acquisitions. The maximum permitted consolidated total leverage ratio will revert to 4.75 for the quarter ended September 30, 2015. As of June 30, 2015, we had approximately $387.1 million of outstanding borrowings and available borrowing capacity of $19.1 million under the Credit Agreement.

At June 30, 2015 and December 31, 2014, letters of credit outstanding under the Credit Agreement were $1.6 million.

Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital deficit was $4.9 million at June 30, 2015.

Cash Flows

The following table reflects cash flows for the applicable periods (in thousands):

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	Six months ended June 30, 2015	2014
Net cash provided by (used in):		
Operating activities	$29,620	$12,411
Investing activities	(61,297)	(117,936)
Financing activities	31,526	108,139

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Operating Activities. Net cash provided by operating activities was $29.6 million for the six months ended June 30, 2015 compared to $12.4 million for the six months ended June 30, 2014. Net cash provided by operating activities for the six months ended June 30, 2015 increased by $17.2 million period over period primarily due to increased gross margin of $20.8 million, and an increase in the change in operating assets and liabilities of $8.2 million. These increases in operating cash flows were offset by increases in direct operating expenses and selling, general and administrative expenses of $7.8 million and $1.3 million, respectively, and an increase in interest expense of $2.6 million due to a higher outstanding borrowings as a result of the Costar Acquisition and funding our capital growth projects during the current year.

One of the primary sources of variability in our cash flows from operating activities is fluctuation in commodity prices, which we partially mitigate by entering into commodity derivatives. Average throughput volume changes also impact cash flow, but have not been as volatile as commodity prices. Our long-term cash flows from operating activities are dependent on commodity prices, average throughput volumes, costs required for continued operations and cash interest expense.

Investing Activities. Net cash used in investing activities was $61.3 million for the six months ended June 30, 2015 compared to $117.9 million for the six months ended June 30, 2014. Cash used in investing activities for the six months ended June 30, 2015 decreased by $56.6 million period over period primarily due to a lack of acquisitions of $110.9 million and cash received of $7.4 million primarily related to reimbursement for certain capital expenditures that we have incurred, or will incur, related to the Costar Acquisition; offset by higher capital expenditures of $66.5 million primarily related to the Lavaca and Bakken Systems.

Financing Activities. Net cash provided by financing activities was $31.5 million for the six months ended June 30, 2015 compared to $108.1 million for the six months ended June 30, 2014. Cash provided by financing activities for the six months ended June 30, 2015 decreased by $76.6 million period over period primarily due to lower proceeds from the issuance of common units to the public of $87.3 million, lack of proceeds from issuance of Series B Units of $30.0 million, and an increase in unit holder distributions of $10.6 million. These decreases in financing cash flows were partially offset by the issuance of Series A-2 units for aggregate proceeds of $45.0 million, and an increase of $8.4 million in net borrowings from our credit facility.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At June 30, 2015, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. There are no other transactions, arrangements, or other relationships associated with our investments in unconsolidated affiliates or related parties that are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources. At June 30, 2015, our off-balance sheet arrangements did not change materially from those listed in under the label "Contractual Obligations" within Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K filed on March 10, 2015.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities. 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.

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Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the six months ended June 30, 2015, capital expenditures totaled $79.7 million including expansion capital expenditures of $76.0 million, maintenance capital expenditures of $2.0 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $1.7 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our partnership agreement.

Integrity Management

Certain operating assets require an ongoing integrity management program under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our total program addresses approximately 93 high consequence areas that require on-going testing pursuant to DOT regulations. Over the course of the seven-year cycle, we expect to incur approximately $6.0 million in integrity management testing expenses.

Distributions

We intend to pay a quarterly distribution though we do not have a legal obligation to make distributions except as provided in our Partnership agreement.

On July 23, 2015, we announced a distribution of $0.4725 per unit for the quarter ended June 30, 2015, or $1.89 per unit on an annualized basis, payable on August 14, 2015 to unitholders of record on August 5, 2015.

Critical Accounting Policies

There were no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K filed on March 10, 2015.

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting standards for revenue recognition. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017, including interim periods therein, as a result of the FASB's recent decision to defer the effective date by one year. We are currently evaluating the method of adoption and impact this standard will have on our condensed consolidated financial statements and related disclosures.

In February 2015, the FASB issued ASU No. 2015-02, Amendments to the Consolidation Analysis. This guidance amends the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015, and early adoption is permitted. The Partnership is currently evaluating the potential impact this standard will have on its condensed consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. This amendment requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, including interim periods therein, and is applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. Given the Partnership's debt issuance costs relate to its revolving debt Credit Facility, the Partnership does not anticipate this standard to alter its current accounting for such costs.

In April 2015, the FASB issued ASU No. 2015-06, Earnings Per Share (Topic 260). This guidance clarifies the process for updating historical earnings per unit disclosures when a drop-down transaction occurs between entities under common control. Pursuant to the amendment, the previously reported earnings per unit measure presented in the historical financial statements would not change as a result of the drop-down transaction. ASU 2015-06 is effective for annual reporting periods beginning after December 15, 2015, and for interim periods within those fiscal years. Early adoption is permitted. The Partnership has evaluated this guidance and determined it is consistent with our policy and historical presentation of earnings per unit.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The following should be read in conjunction with the information provided in Part II, Item 7A of our Annual Report under the caption "Quantitative and Qualitative Disclosures about Market Risk". We enter into derivative agreements to hedge exposure to commodity prices associated with natural gas, NGLs, and crude oil. We are exposed to non-performance by our counterparties on our open derivative contracts. We do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings. We did not post collateral under any of these contracts, as they are secured under the Credit Agreement. We account for our derivative activities whereby each derivative instrument is recorded on the balance sheet as either an asset or liability measured at fair value. Refer to Note 7 "Derivatives" for further details.

As of June 30, 2015, we have hedged approximately 31 percent of our expected exposure to NGL prices and 34 percent of our expected exposure to oil prices through the end of 2015.

The table below sets forth certain information regarding the financial instruments used to hedge our commodity price risk as of June 30, 2015:

Commodity	Instrument	Volumes (a)	Weighted Average Price	Period	Fair value at June 30, 2015 (in thousands)
NGLs (gal)	Swaps	(3,780,000)	$0.97	Jul 2015 - Dec 2015	$331
Oil (Bbl)	Swaps	(13,200)	$62.43	Jul 2015 - Dec 2015	22
					$353

(a) Contracted and notional volumes represented as a net short financial position by instrument.

Interest Rate Risk

During the six months ended June 30, 2015, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. During the second quarter of 2013, we entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting the cash flows related to $100.0 million of our long-term variable rate debt into fixed rate cash flows. The interest rate swap will expired August 1, 2015.

The credit markets have continued to experience historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will begin to tighten, resulting in higher interest rates. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $2.0 million on an unhedged basis for the six months ended June 30, 2015.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to the management of our General Partner, including our General Partner's principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. Due to the material weakness in internal control over financial reporting described below, our Certifying Officers have concluded our disclosure controls and procedures are ineffective as of June 30, 2015.

We did not design and maintain effective internal controls over the completeness and accuracy of spreadsheets. Specifically, our guidelines were not precise enough in describing the level of review to be performed regarding the inputs, assumptions, and formulas used in spreadsheets. This control deficiency resulted in audit adjustments to goodwill, intangible assets, and amortization expense during the year ended December 31, 2014 and immaterial out-of-period adjustments to our consolidated financial statements for each of the interim periods in the year-ended December 31, 2014. Additionally, this control deficiency could result in a misstatement of the account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management determined that this control deficiency constitutes a material weakness.

Remediation plan for spreadsheet deficiencies

With respect to the identified material weakness, we are developing specific guidance describing the level of reviews to be performed on our key spreadsheets used in the preparation and analysis of accounting and financial information, including validating inputs, assumptions and formulas. We will also continue to focus on continuing education for our current accounting and finance staff.

Inherent limitations of internal controls

Our management, including our Certifying Officers, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) will prevent or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations with a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Therefore, management monitors the Partnership's disclosure controls and procedures and make modifications, as necessary, with the intent that the disclosure controls and procedures will be adequately designed and operating effectively to prevent or detect material misstatements to its consolidated financial statements and to deter fraud.

The management of our General Partner evaluated, with the participation of the Certifying Officers, the effectiveness of our Disclosure Controls and procedures as of the end of the period covered by this report, pursuant to Rule

13a-15(e) and 15d-15(e) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of June 30, 2015, the end of the period covered by this report, our Disclosure Controls and procedures were ineffective.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the six months ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Certifying Officers pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Quarterly Report on Form 10-Q as Exhibits 31.1 and 31.2. The certifications of our Certifying Officers pursuant to 18 U.S.C. 1350 are furnished with this Quarterly Report on Form 10-Q as Exhibits 32.1 and 32.2.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainly, our management believes that the resolution of any of our pending proceeds will not have a material adverse effect on our financial condition or results of operations.

Item 1A. Risk Factors

Information about material risks related to our business, financial conditions and results of operations for the quarter ended June 30, 2015, does not materially differ from those set out in Part I, Item 1A of our Annual Report.

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Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (filed as Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated August 9, 2013 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 15, 2013).
3.3	Amendment to the Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated October 28, 2013 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 1, 2013).
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4.2	Registration Rights Agreement, dated August 20, 2014, by and among American Midstream Partners, LP and the purchasers named therein (filed as Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 20, 2014).
4.3	Securities Agreement, dated October 13, 2014, by and among American Midstream Partners, LP, Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC (filed as Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on October 15, 2014).
10.1	Second Series A-2 Convertible Preferred Unit Purchase Agreement dated June 30, 2015 by and between American Midstream Partners, LP and Magnolia Infrastructure Partners, LLC (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on July 2, 2015).
31.1*	Certification of Stephen W. Bergstrom, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the June 30, 2015 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*	Filed herewith
**	Submitted electronically herewith

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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.

Date: August 10, 2015

AMERICAN MIDSTREAM PARTNERS, LP

By:	American Midstream GP, LLC, its general partner
By:	/s/ Stephen W. Bergstrom
Name:	Stephen W. Bergstrom
Title:	President and Chief Executive Officer (principal executive officer)
By:	/s/ Daniel C. Campbell
Name:	Daniel C. Campbell
Title:	Senior Vice President & Chief Financial Officer (principal financial officer)

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