American Midstream Partners, LP
Form 10-Q
May 09, 2016
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
March 31, 2016
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. (Check one):

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 30,896,502 common units, 9,499,370 Series A Units, and 8,571,429 Series C Units of American Midstream Partners, LP outstanding as of May 6, 2016. 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.
Bbl/d	Barrels per day.
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	Generally accepted accounting principles in the United States of America
Gal	Gallons.
Mgal/d	Thousand gallons per day.
MBbl	Thousand barrels.
MMBbl	Million barrels.
MMBtu	Million British thermal units.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
MMcf/d	Million cubic feet per day.
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)

	March 31, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$—	$ —
Accounts receivable	6,258	3,181
Unbilled revenue	14,519	15,559
Risk management assets	206	365
Other current assets	6,827	10,094
Total current assets	27,810	29,199
Property, plant and equipment, net	650,285	648,013
Goodwill	16,262	16,262
Intangible assets, net	99,877	100,965
Investment in unconsolidated affiliates	81,047	82,301
Other assets, net	14,221	14,556
Total assets	$889,502	$ 891,296
Liabilities and Partners’ Capital		
Current liabilities		
Accounts payable	$5,255	$ 4,667
Accrued gas purchases	6,532	7,281
Accrued expenses and other current liabilities	25,861	25,035
Current portion of long-term debt	1,672	2,338
Risk management liabilities	163	—
Total current liabilities	39,483	39,321
Risk management liabilities	730	—
Asset retirement obligations	28,750	28,549
Other liabilities	505	1,001
Long-term debt	549,400	525,100
Deferred tax liability	6,120	5,826
Total liabilities	624,988	599,797
Commitments and contingencies (See Note 14)		
Convertible preferred units		
Series A convertible preferred units (9,499 thousand and 9,210 thousand units issued and outstanding as of March 31, 2016 and December 31, 2015, respectively)	174,183	169,712
Equity and partners' capital		
General Partner Interest (542 thousand and 536 thousand units issued and outstanding as of March 31, 2016 and December 31, 2015, respectively)	(108,036)	(104,853)
Limited Partner Interests (30,890 thousand and 30,427 thousand units issued and outstanding as of March 31, 2016 and December 31, 2015, respectively)	193,711	188,477
Series B convertible units (zero and 1,350 thousand units issued and outstanding as of March 31, 2016 and December 31, 2015, respectively)	—	33,593
Accumulated other comprehensive income (loss)	54	40
Total partners’ capital	85,729	117,257

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Noncontrolling interests	4,602	4,530
Total equity and partners' capital	90,331	121,787
Total liabilities, equity and partners' capital	$889,502	$891,296

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

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

	Three months ended March 31,	
	2016	2015
Revenue	$46,123	$64,462
Gain (loss) on commodity derivatives, net	(103)	147
Total revenue	46,020	64,609
Operating expenses:		
Purchases of natural gas, NGLs and condensate	16,913	28,978
Direct operating expenses	14,521	13,867
Selling, general and administrative expenses	8,534	6,935
Equity compensation expense	1,084	1,698
Depreciation, amortization and accretion expense	10,094	9,689
Total operating expenses	51,146	61,167
Gain (loss) on sale of assets, net	10	(8)
Operating income (loss)	(5,116)	3,434
Other income (expense):		
Interest expense	(5,872)	(2,610)
Earnings in unconsolidated affiliates	7,343	167
Net income (loss) before income tax (expense) benefit	(3,645)	991
Income tax (expense) benefit	(319)	(156)
Net income (loss) from continuing operations	(3,964)	835
Income (loss) from discontinued operations, net of tax	—	5
Net income (loss)	(3,964)	840
Net income (loss) attributable to noncontrolling interests	(13)	14
Net income (loss) attributable to the Partnership	$(3,951)	$826
General Partner's Interest in net income (loss)	$(52)	$10
Limited Partners' Interest in net income (loss)	$(3,899)	$816
Distribution declared per common unit (a)	$0.4725	$0.4725
Limited partners' net income (loss) per common unit (See Note 11):		
Basic and diluted:		
Income (loss) from continuing operations	$(0.33)	$(0.19)
Income (loss) from discontinued operations	—	—
Net income (loss)	$(0.33)	$(0.19)
Weighted average number of common units outstanding:		
Basic and diluted	30,819	22,703

(a) Distributions declared and paid during the three months ended March 31, 2016 and 2015 related to prior periods' operations.

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 March 31,	
	2016	2015
Net income (loss)	$(3,964)	$840
Unrealized gain (loss) on postretirement benefit plan assets and liabilities	14	(11)
Comprehensive income (loss)	(3,950)	829
Less: Comprehensive income (loss) attributable to noncontrolling interests	(13)	14
Comprehensive income (loss) attributable to the Partnership	$(3,937)	$815

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, 2014	$(2,450)	$294,695	$32,220	$2	$324,467	$4,717
Net income (loss)	10	816	—	—	826	14
Issuance of Series B units	—	—	420	—	420	—
Unitholder contributions	23	—	—	—	23	—
Unitholder distributions	(1,495)	(14,496)	—	—	(15,991)	—
Net distributions to noncontrolling interests	—	—	—	—	—	(37)
LTIP vesting	(2,117)	2,313	—	—	196	—
Tax netting repurchase	—	(725)	—	—	(725)	—
Equity compensation expense	1,501	—	—	—	1,501	—
Other comprehensive income (loss)	—	—	—	(11)	(11)	—
Balances at March 31, 2015	$(4,528)	$282,603	$32,640	$(9)	$310,706	$4,694
Balances at December 31, 2015	$(104,853)	$188,477	$33,593	$40	$117,257	$4,530
Net income (loss)	(52)	(3,899)	—	—	(3,951)	(13)
Issuance of common units, net of offering costs	—	(104)	—	—	(104)	—
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B units	—	33,593	(33,593)	—	—	—
Unitholder contributions	92	—	—	—	92	—
Unitholder distributions	(2,087)	(19,430)	—	—	(21,517)	—
Net contributions from noncontrolling interests	—	—	—	—	—	85
LTIP vesting	(2,041)	2,041	—	—	—	—
Tax netting repurchase	—	(150)	—	—	(150)	—
Equity compensation expense	905	—	—	—	905	—
Other comprehensive income (loss)	—	—	—	14	14	—
Balances at March 31, 2016	$(108,036)	$193,711	$—	$54	$85,729	$4,602

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 Cash Flows
(Unaudited, in thousands)

	Three months ended March 31,	
	2016	2015
Cash flows from operating activities		
Net income (loss)	$(3,964)	$ 840
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	10,094	9,689
Amortization of deferred financing costs	465	338
Amortization of weather derivative premium	219	241
Unrealized (gain) loss on commodity derivatives, net	833	(55)
Non-cash compensation	1,084	1,720
Postretirement expense (benefit)	—	8
(Gain) loss on sale of assets, net	(10)	(8)
Earnings in unconsolidated affiliates	(7,343)	(167)
Distributions from unconsolidated affiliates	7,343	167
Deferred tax expense (benefit)	294	158
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	(3,077)	(3,414)
Unbilled revenue	1,040	3,515
Other current assets	3,265	917
Other assets, net	41	49
Accounts payable	(209)	(151)
Accrued gas purchases	(749)	(3,048)
Accrued expenses and other current liabilities	(435)	(1,702)
Asset retirement obligations	—	(83)
Other liabilities	(674)	88
Net cash provided by operating activities	8,217	9,102
Cash flows from investing activities		
Cost of acquisitions, net of cash acquired and settlements	—	183
Additions to property, plant and equipment	(18,070)	(38,922)
Proceeds from disposals of property, plant and equipment	29	2,800
Investment in unconsolidated affiliates	(3,546)	—
Proceeds from equity method investments, return of capital	6,172	833
Restricted cash	—	6,450
Net cash used in investing activities	(15,415)	(28,656)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	(149)	(148)
Unitholder contributions	92	—
Unitholder distributions	(17,046)	(12,159)
Issuance of Series A Units, net of issuance costs	—	20,000
Net contributions from (distributions to) noncontrolling interests	85	(37)
LTIP tax netting unit repurchase	(150)	(725)
Deferred financing costs	(135)	(163)
Payments on other debt	(666)	(1,613)
Borrowings on other debt	867	—

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Payments on long-term debt	(32,450)	(54,200)
Borrowings on long-term debt	56,750	68,100
Net cash provided by financing activities	7,198	19,055
Net increase (decrease) in cash and cash equivalents	—	(499)
Cash and cash equivalents		
Beginning of period	—	499
End of period	$—	$—
Supplemental cash flow information		
Interest payments, net	$4,537	$2,290
Supplemental non-cash information		
(Decrease) increase in accrued property, plant and equipment	$(164)	$(3,678)
Accrued and paid-in-kind unitholder distribution for Series A Units	4,471	3,411
Paid-in-kind unitholder distribution for Series B Units	—	420
Cancellation of escrow units	6,817	—

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, Basis of Presentation and Summary of Significant Accounting Policies

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 owning, 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 primarily in a number 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; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products, all through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines, three marine terminal sites, and one crude oil pipeline. We also own a 66.7% non-operated interest in Main Pass Oil Gathering Company ("MPOG"), a crude oil gathering and processing system, a 50% undivided, non-operated interest in the Burns Point Plant, a natural gas processing plant, a 47% non-operated interest in Mesquite, an off-spec condensate fractionation project, and a 12.9% non-operated indirect interest in the Delta House floating production system and related pipeline infrastructure ("Delta House"). Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas and the Gulf of Mexico, provide critical infrastructure that links producers of natural gas, crude oil, 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 1.8 million barrels of storage capacity across three marine terminal sites.

Basis of Presentation

These unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("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 months ended March 31, 2016, are not necessarily indicative of the results that may be expected for the year ending December 31, 2016. 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, 2015, filed with the Securities and Exchange Commission (the "SEC") on March 7, 2016 (“Annual Report.”)

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.

Investment in Unconsolidated Affiliates

Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method and are reported in Investment in unconsolidated affiliates in the accompanying condensed consolidated balance sheets.

The Partnership believes the equity method is an appropriate means for it to recognize increases or decreases, measured by GAAP, in the economic resources underlying the investments. Regular evaluation of these investments is appropriate to evaluate any

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potential need for impairment. The Partnership uses evidence of a loss in value to identify if an investment has declined in value, other than a temporary decline.

The Partnership accounts for its 66.7% non-operated interest in MPOG, its 47.0% non-operated interest in Mesquite and its 12.9% non-operated indirect interest in Delta House under the equity method.

Use of Estimates

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 assumptions, including estimates of 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.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("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. ASU 2015-14 was subsequently issued and deferred the effective date to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that period. In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606) - Principal Versus Agent Considerations as further clarification on principal versus agent considerations. We are currently evaluating the method of adoption and impact these standards will have on our consolidated financial statements and related disclosures.

In February 2015, the FASB issued ASU No. 2015-02, Consolidation - Amendments to the Consolidation Analysis, which amends the current consolidation guidance. The amendments affect both the variable interest entity ("VIE") and voting interest entity ("VOE") consolidation models. The standard is effective for public reporting entities in the fiscal periods beginning after December 15, 2015. The Partnership completed an assessment of its current VIEs in connection with the adoption of this standard in the current quarter, and determined no change to its previous assessments were required.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). This amendment requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. We are currently evaluating the method of adoption and impact this standard will have on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, Derivatives and Hedging (Topic 815). This amendment clarifies existing guidance for assessing embedded call (put) options that are closely related to their debt hosts using a four-step decision sequence. ASU 2016-03 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted. The Partnership has evaluated this guidance and determined it will not have a material impact on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-07, Investments - Equity Method and Joint Ventures (Topic 323). This amendment eliminates the requirement to retroactively adopt the equity method of accounting when a previous investment becomes qualified as a result of an increase in the level of ownership interest or degree of influence. ASU 2016-07 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal periods. Early adoption is permitted. The Partnership has evaluated this guidance and determined it will not have a material impact on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-09, Compensation - Stock Compensation (Topic 718). This amendment involves the simplification of several aspects of accounting for share-based payment transactions, including income tax consequences,

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classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal periods. Early adoption is permitted. We are currently evaluating the method of adoption and impact this standard will have on our consolidated financial statements and related disclosures.

2. Concentration of Credit Risk and Trade Accounts Receivable

Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas and the Gulf of Mexico, provide critical infrastructure that links customers of crude oil, 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 reduced the concentration which may affect our overall credit risk. Our customers' historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable; however, for the three months ended March 31, 2016 and 2015, no allowances on or significant write-offs of accounts receivable were recorded.

During the three months ended March 31, 2016, one customer accounted for 13% of the Partnership's consolidated revenue, compared to 10% for the three months ended March 31, 2015.

3. Other Current Assets

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

	March 31, 2016	December 31, 2015
Prepaid insurance	$2,705	$ 3,948
Other prepaid amounts	2,060	2,866
Other current assets	2,062	3,280
	$6,827	$ 10,094

4. Derivatives

Commodity Derivatives

To limit the effect of commodity price changes and maintain our cash flow and the economics of our development plans, we enter into commodity derivative 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 commodity price increases. 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 March 31, 2016, the aggregate notional volume of our commodity derivatives was 7.7 million gallons of NGLs, natural gasoline, and crude oil equivalent for 2016 production.

We enter into commodity derivative 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 March 31, 2016, 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

To manage the impact of the interest rate risk associated with our credit facility, we enter into interest rate swaps from time to time, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows. As

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of March 31, 2016, the notional amount of our interest rate swap was $200.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap will expire September 3, 2019.

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 derivative is 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 derivative was 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 $0.1 million as of March 31, 2016.
As of March 31, 2016 and December 31, 2015, 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):

	Gross Risk Management Assets		Gross Risk Management (Liabilities)		Net Risk Management Assets (Liabilities)	
Balance Sheet Classification	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015
Current	$ 206	$ 365	$ —	$ —	$ 206	$ 365
Noncurrent	—	—	—	—	—	—
Total assets	$ 206	$ 365	$ —	$ —	$ 206	$ 365
Current	$ —	$ —	$ (163)	$ —	$ (163)	$ —
Noncurrent	—	—	(730)	—	(730)	—
Total liabilities	$ —	$ —	$ (893)	$ —	$ (893)	$ —

For the three months ended March 31, 2016 and 2015, 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):

	Three months ended March 31, Gain (loss) on derivatives	
Statement of Operations Classification	Realized	Unrealized
2016		
Gain (loss) on commodity derivatives, net	$ —	$ (103)
Interest expense	—	(730)
Direct operating expenses	(219)	—
Total	$ (219)	$ (833)
2015		
Gain (loss) on commodity derivatives, net	$ 139	$ 8
Interest expense	(102)	47

Direct operating expenses	(241)	—
Total	$(204)	$ 55

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

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The fair value of our commodity and interest rate derivatives instruments are 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 three months ended March 31, 2016 and 2015.

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 March 31, 2016 and December 31, 2015 (in thousands):

	Carrying Amount	Estimated Fair Value of the Assets (Liabilities)			
		Level 1	Level 2	Level 3	Total
Commodity derivative instruments, net					
March 31, 2016	$ (103)	$ —	$ (103)	$ —	$ (103)
December 31, 2015	—	—	—	—	—
Interest rate swap					
March 31, 2016	$ (730)	$ —	$ (730)	$ —	$ (730)
December 31, 2015	—	—	—	—	—

The unamortized portion of the premium paid to enter the weather derivative described in Note 4 "Derivatives" is included within Risk management assets on our condensed consolidated balance sheets but is not included as part of the above table as it is recorded at amortized carrying cost, not fair value.

6. Property, Plant and Equipment, Net

Property, plant and equipment, net, as of March 31, 2016 and December 31, 2015 were as follows (in thousands):

	Useful Life (in years)	March 31, 2016	December 31, 2015
Land	N/A	$5,282	$ 5,282
Construction in progress	N/A	52,684	46,045
Buildings and improvements	4 to 40	9,864	9,864
Processing and treating plants	8 to 40	101,838	97,784
Pipelines and compressors	3 to 40	550,826	554,400
Storage	20 to 40	58,226	58,394
Equipment	5 to 20	26,317	22,207
Total property, plant and equipment		805,037	793,976
Accumulated depreciation		(154,752)	(145,963)
Property, plant and equipment, net		$650,285	$ 648,013

Of the gross property, plant and equipment balances at March 31, 2016 and December 31, 2015, $118.2 million and $111.9 million, respectively, were related to AlaTenn, Midla and HPGT, our FERC regulated interstate and intrastate assets.

Capitalized interest was $0.5 million and $0.2 million for the three months ended March 31, 2016 and 2015, respectively.

Depreciation expense was $8.8 million and $7.9 million for the three months ended March 31, 2016 and 2015, respectively.

In February 2016, the Partnership reached a settlement of certain indemnification claims with Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC, the sellers in the Partnership's acquisition of 100% of the membership interests of Costar Midstream, L.L.C. ("Costar" and such acquisition, the "Costar Acquisition"), whereby 1,034,483 of the common units held in

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escrow were returned to the Partnership and canceled, while the Partnership agreed to pay the Costar sellers an additional $0.3 million in cash. The net impact of this settlement was recorded as a reduction in property, plant and equipment in the first quarter of 2016.

7. Goodwill and Intangible Assets, Net

The carrying value of goodwill as of March 31, 2016 and December 31, 2015, was $16.3 million and $16.3 million, respectively. Goodwill as of March 31, 2016 and December 31, 2015 related to our Terminal segment.

The goodwill associated with our Terminal segment was contributed to the Partnership as part of the acquisition of Blackwater Midstream Holdings LLC ("Blackwater") and other related subsidiaries from an affiliate of HPIP (the "Blackwater Acquisition"). Goodwill was recorded as 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 acquired.

Intangible assets, net, consists of customer contracts, relationships and dedicated acreage agreements identified as part of the Costar, Lavaca and Blackwater acquisitions. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging from 10 years to 30 years. Intangible assets, net, consist of the following (in thousands):

	March 31, 2016	December 31, 2015
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	$(12,101)	$(12,101)
Customer relationships	(3,768)	(3,124)
Dedicated acreage	(3,105)	(2,661)
	$(18,974)	$(17,886)
Net carrying amount:		
Customer contracts	$—	$—
Customer relationships	49,632	50,276
Dedicated acreage	50,245	50,689
	$99,877	$100,965

Amortization expense on our intangible assets totaled $1.1 million and $1.6 million for the three months ended March 31, 2016 and 2015, respectively.

8. Investment in unconsolidated affiliates

The following table presents the activity in the Partnership's equity investments as of March 31, 2016 and December 31, 2015 (in thousands):

	MPOG	Mesquite	Delta House	
	66.7%	47%	12.9%	Total
Balances at December 31, 2015	$7,179	$18,597	$56,525	$82,301

Earnings in unconsolidated affiliates	230	—	7,113	7,343
Contributions	428	4,490	—	4,918
Distributions	(895)	—	(12,620)	(13,515)
Balances at March 31, 2016	$6,942	$23,087	$51,018	$81,047

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The following tables present the summarized combined financial information for the Partnership's equity investments (amounts represent 100% of investee financial information):

Balance Sheets:	March 31, 2016	December 31, 2015
Current assets	$ 2,837	$ 2,086
Non-current assets	275,496	288,617
Current liabilities	286	366
Non-current liabilities	23,957	23,617

	Three months ended March 31,	
Income Statements:	2016	2015
Total revenue	$ 29,330	$ 2,436
Operating expense	892	970
Net income	27,181	243

The unconsolidated affiliates described above were each determined to be Variable Interest Entities ("VIE") due to disproportionate economic interests and decision making rights. In each case, the Partnership lacks the power to direct the activities that most significantly impact each unconsolidated affiliate's economic performance. As the Partnership does not hold a controlling financial interest in these affiliates, the Partnership accounts for its related investments using the equity method. The Partnership’s maximum exposure to loss related to each VIE is limited to its equity investment as presented on the condensed consolidated balance sheet at March 31, 2016. In each case, the Partnership is not obligated to absorb losses greater than its proportional ownership percentages indicated above. In each case, the Partnership’s right to receive residual returns is not limited to any amount less than the proportional ownership percentages indicated above.

9. Accrued Expenses and Other Current Liabilities

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

	March 31, 2016	December 31, 2015
Current portion of asset retirement obligation (a)	$ 6,825	$ 6,822
Accrued capital expenditures	3,092	3,984
Accrued expenses	5,744	3,178
Due to related parties	1,962	3,894
Bank overdraft	2,589	1,722
Other	5,649	5,435
	$ 25,861	$ 25,035

(a) Associated with certain Gathering and Processing assets expected to be remediated in the next twelve months.

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10. Debt Obligations

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

	March 31, 2016	December 31, 2015
Revolving credit facility	$549,400	$ 525,100
Other debt	1,672	2,338
Total debt	551,072	527,438
Less: current portion	1,672	2,338
Long-term debt	$549,400	$ 525,100

On September 14, 2014, the Partnership entered into the Amended and Restated Credit Agreement, which was amended by the First Amendment and Incremental Commitment Agreement dated as of September 18, 2015 (as amended, the "Credit Agreement"), which provides for maximum borrowings equal to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million 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 under the Credit Agreement.

Our obligations under the Credit Agreement are secured by a lien on substantially all of our assets. 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 for the prior twelve month period adjusted in accordance with the Credit Agreement (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 that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by not less than 2.50 times. The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $750.0 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 three months ended March 31, 2016 and 2015, the weighted average interest rate on borrowings under our Credit Agreement was approximately 4.13% and 2.37%, respectively.

As of March 31, 2016, our consolidated total leverage was 5.17 and our interest coverage ratio was 6.74, which was in compliance with the consolidated total leverage ratio and interest coverage ratio tests in accordance with the financial covenants required in our Credit Agreement. At March 31, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $1.8 million.

As of March 31, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions, or drop down transactions, as well as the associated financing for such initiatives. If required, ArcLight Capital Partners, LLC, which controls the General Partner of the Partnership, has agreed to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through December 31, 2016.

Other debt

Other debt represents insurance premium financing in the original amount of $3.0 million bearing interest at 3.95% per annum, which is repayable in equal monthly installments of approximately $0.3 million through the third quarter of 2016.

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11. Partners’ Capital and Convertible Preferred Units

Our capital accounts are comprised of approximately 1.3% notional general partner interests and 98.7% limited partner interests as of March 31, 2016. 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 interests held by our General Partner. Pursuant to our Partnership Agreement, our General Partner participates in losses and distributions based on its interest. The General Partner's participation in the allocation of losses and distributions is not limited and therefore, such participation can result in a deficit to its capital account. As such, allocation of losses and distributions for previous transactions between entities under common control has resulted in a deficit to the General Partner's capital account included in our condensed consolidated balance sheets.

Affiliates of our General Partner hold and participate in distributions on our Series A Units with such distributions being made in paid-in-kind Series A 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 Units are converted into common units. The Series A Units are entitled to vote along with Limited Partner common unitholders and such units are currently convertible to Limited Partner common units.

On February 1, 2016, all outstanding Series B Units were converted on a one-to-one basis to common units. Prior to the conversion of the Series B Units into common units, our General Partner held and participated in distributions on our 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 were entitled to vote along with the holders of Limited Partner common units prior to conversion.

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $0.1 million from our General Partner as consideration for the issuance of 6,225 additional notional general partner units for the three months ended March 31, 2016. There were no such contributions for the three months ended March 31, 2015.

Outstanding Units

The number of units outstanding as of March 31, 2016 and December 31, 2015, respectively, were as follows (in thousands):

	March 31, 2016	December 31, 2015
Series A convertible preferred units	9,499	9,210
Series B convertible units	—	1,350
Limited Partner common units	30,890	30,427
General Partner units	542	536

Distributions

We made cash distributions as follows (in thousands):

	Three months ended March 31,	
	2016	2015

Series A convertible preferred units	$—	$—
Limited Partner common units	15,018	10,713
General Partner units	222	158
General Partners' incentive distribution rights	1,806	1,288
	$17,046	$12,159

On April 25, 2016, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per unit for the first quarter ended March 31, 2016, or $1.65 per unit on an annualized basis. The cash distribution is expected to be paid on May 13, 2016, to unitholders of record as of the close of business on May 4, 2016. At March 31, 2016, we had accrued $4.5 million for the paid-in-kind Series A Units that will be issued in May 2016.

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For the three months ended March 31, 2016, the Partnership issued 288,910 of paid-in-kind Series A Units and recorded accrued and paid-in-kind unitholder distributions for Series A Units with a fair value of $4.5 million. For the three months ended March 31, 2015, the Partnership issued 164,149 of paid-in-kind Series A Units and recorded accrued and paid-in-kind unitholder distributions for Series A Units with a fair value of $3.4 million.

The fair value of the paid-in-kind Series A Unit distributions for all quarters presented was determined primarily using the market and income approaches, utilizing significant inputs which are not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Under the income approach the fair value estimates for all periods presented were based on i) present value of estimated future contracted distributions, ii) option values ranging from $0.02 per unit to $1.88 per unit using a Black-Scholes model, iii) assumed discount rates of 10.0%, and iv) assumed distribution growth rates of 1.0%.

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 distributions on Series A Units, declared distributions on the Series B Units, limited partner units and 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 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 March 31,	
	2016	2015
Net income (loss) from continuing operations	$(3,964)	$835
Less: Net income (loss) attributable to noncontrolling interests	(13)	14
Net income (loss) from continuing operations attributable to the Partnership	(3,951)	821
Less:		
Distributions on Series A Units	4,471	3,411
Declared distributions on Series B Units	—	420
General partner's distribution	2,028	1,447
General partner's share in undistributed loss	(337)	(189)
Net income (loss) from continuing operations available to Limited Partners	(10,113)	(4,268)
Net income (loss) from discontinued operations available to Limited Partners	—	5
Net income (loss) available to Limited Partners	$(10,113)	$(4,263)
Weighted average number of units used in computation of Limited Partners’ net income (loss) per unit (basic and diluted)	30,819	22,703
Limited Partners' net income (loss) from continuing operations per unit (basic and diluted)	$(0.33)	$(0.19)
Limited Partners' net income (loss) from discontinued operations per unit (basic and diluted)	—	—
Limited Partners' net income (loss) per unit (basic and diluted)	$(0.33)	$(0.19)

12. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 19, 2015, the Board of Directors of our General Partner approved the Third Amended and

Restated Long-Term Incentive Plan, which, subject to unitholder approval, would increase the number of common units authorized for issuance by 6,000,000 common units. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan (as amended and as currently in effect as of the date hereof, the "LTIP") to increase the number of available awards by 6,000,000 common units. At March 31, 2016 and December 31, 2015, there were 4,937,627 and 15,484 common unit, respectively, available for future grant under the LTIP.

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All such equity-based awards issued under the LTIP consist of phantom units, Distribution Equivalent Rights ("DERs") or Option Grants. DERs and options have been granted on a limited basis. Future awards, such as options and DERs, may be granted at the discretion of the Compensation Committee and subject to approval by the Board of Directors of our General Partner.

Phantom Unit Awards. Ownership in the phantom unit awards is subject to forfeiture until the vesting date. The LTIP is administered by the Compensation Committee of 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. Under the LTIP, grants issued typically vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment.

In December 2015, the Board of Directors of our General Partner approved a grant of 200,000 phantom units under the LTIP which contains distribution equivalent rights based on the extent to which the Partnership's Series A Preferred Unitholders receive distributions in cash and will vest in one lump sum installment on the three year anniversary of the date of grant, subject to acceleration in certain circumstances.

The following table summarizes our phantom unit-based awards, in units:

	Three months ended March 31, 2016	
	Units	Weighted-Average Grant Price
Outstanding at beginning of period	569,759	$ 13.15
Granted	1,131,700	0.92
Forfeited	(30,454)	9.88
Vested	(171,402)	11.91
Outstanding at end of period	1,499,603	$ 4.13

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our limited partner common units at the grant date. Compensation costs related to these awards, including amortization, for the three months ended March 31, 2016 and 2015 were $1.1 million and $1.7 million, respectively, which are classified as Equity compensation expense in our condensed consolidated statements of operations and in partners' capital on our condensed consolidated balance sheets.

The total fair value of vested units at the time of vesting was $0.9 million and $2.3 million for the three months ended March 31, 2016 and 2015, respectively.

Equity compensation expense related to unvested awards not yet recognized at March 31, 2016 and 2015 was $5.8 million and $6.6 million, respectively, and the weighted average period over which this cost is expected to be recognized as of March 31, 2016 is approximately 2.6 years.

Performance and Service Condition Awards. In November 2015, the Board of Directors of our General Partner modified awards that introduced certain performance and service conditions that we believe are probable, amounting to $2.0 million payable in a variable amount of phantom units awards at the time of grant. As such, these awards are accounted for as liability-based awards and equity-based compensation is to be accrued from the service-inception date through the estimated date of meeting both the performance and service conditions. Compensation costs related to these awards for the three months ended March 31, 2016 was $0.2 million. Compensation cost related to unvested awards not yet recognized at March 31, 2016 was $1.3 million.

Option to Purchase Common Units. In December 2015, the Board of Directors of our General Partner approved the grant of an option to purchase 200,000 common units of the Partnership at an exercise price per unit equal to $7.50 (the “Option Grant”). The Option Grant will vest in one lump sum installment on January 1, 2019, subject to acceleration in certain circumstances, and will expire on March 15th of the calendar year following the calendar year in which it vests.

The following table summarizes our Option Grant awards, in units:

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	Three months ended March 31, 2016	
	Units	Weighted-Average Exercise Price
Outstanding at beginning of period	200,000	$ 7.50
Granted	—	—
Forfeited	—	—
Vested	—	—
Outstanding at end of period	200,000	$ 7.50

Compensation costs related to these awards for the three months ended March 31, 2016 was immaterial. Compensation cost related to unvested awards not yet recognized at March 31, 2016 was $0.1 million.

13. Income Taxes

With the exception of certain subsidiaries in our Terminals Segment, the Partnership is not subject to U.S. federal or state income taxes as such income taxes are generally borne by our unitholders through the allocation of our taxable income (loss) to them. The State of Texas does impose a franchise tax that is assessed on the portion of our taxable margin that is apportioned to Texas.

Income tax expense for the three months ended March 31, 2016 was $0.3 million, resulting in an effective tax rate of 8.8%. For the three months ended March 31, 2015, income tax expense was $0.2 million, resulting in an effective tax rate of 15.7%.

The effective tax rates for the three months ended March 31, 2016 and 2015, 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.

14. 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 October 8, 2014, American Midstream (Midla), LLC ("Midla") reached an agreement in principle with its customers regarding the interstate pipeline that traverses Louisiana and Mississippi in order to provide continued service to its customers while addressing safety concerns with the existing pipeline.

On April 16, 2015, the FERC approved the stipulation and agreement (the "Midla Agreement") allowing Midla to retire the existing 1920s vintage pipeline and replace it 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, which was approved on December 17, 2015. Construction is expected to commence in the first half of 2016 with service beginning in late 2016. Under the Midla Agreement, Midla plans to execute long-term agreements seeking to recover its investment in the Midla-Natchez Line.

Exit and disposal costs

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On March 9, 2016, management committed and communicated to its employees a corporate relocation plan. The plan includes relocation assistance or one-time termination benefits for employees who render service through to their respective termination date. We have estimated the fair value of the initial obligation of approximately $4.3 million of which $0.7 million has been recorded in Accrued expenses and other current liabilities as of March 31, 2016. Charges associated with relocation assistance and one-time termination benefits will be recognized ratably over the requisite service period and presented in Selling, general and administrative expenses. We expect the plan to be complete by the fourth quarter of 2016.

15. Related-Party Transactions

Employees of our General Partner are assigned to work for the Partnership or other affiliates of our General Partner. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our General Partner to American Midstream, LLC, which, in turn, charges the appropriate subsidiary or affiliate. Our General Partner does not record any profit or margin for the administrative and operational services charged to us. During the three months ended March 31, 2016 and 2015, administrative payroll and operational services expenses of $8.1 million and $7.3 million, respectively, were charged to the Partnership by our General Partner.

For the three months ended March 31, 2016 and 2015, our General Partner incurred approximately $0.3 million and $0.4 million, respectively, of costs related to business development compensation that were funded by the Partnership.

During the first quarter of 2015, the Partnership and an affiliate of HPIP entered into an arrangement under which the affiliate reimbursed the Partnership for rights-of-way purchased on the affiliates' behalf for approximately $2.8 million.

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 affiliate's behalf. For the three months ended March 31, 2016 and 2015, the Partnership recognized $0.2 million and $0.4 million, respectively, in management fee income that has been recorded as a reduction to Selling, general and administrative expenses. For the three months ended March 31, 2016 and 2015, an affiliate of our General Partner also incurred approximately $0.5 million and $0.1 million, respectively, of costs associated with reimbursable costs incurred on behalf of these affiliates.

As of March 31, 2016 and December 31, 2015, the Partnership had $2.0 million and $3.8 million, respectively, due to our General Partner, which has been recorded in Accrued expenses and other current liabilities and relates primarily to compensation. This payable is generally settled on a quarterly basis. As of March 31, 2016, the Partnership also had $0.1 million due from affiliates, which has been recorded in Other current assets.

16. Reportable Segments

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

Gathering and Processing

Our Gathering and Processing segment provides "wellhead-to-market" services to producers of natural gas and crude oil, which include transporting raw natural gas from the wellhead through gathering systems, treating the raw natural gas, processing raw natural gas into 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, including local distribution companies, or 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 petroleum products, distillates, chemicals and agricultural products.

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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 a performance measure utilized by management to monitor the results of each segment.

The following tables set forth our segment information for the three months ended March 31, 2016 and 2015 (in thousands):

	Three months ended March 31, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$31,148	$ 10,227	$ 4,748	$46,123
Gain (loss) on commodity derivatives, net	(103)	—	—	(103)
Total revenue	31,045	10,227	4,748	46,020
Operating expenses:				
Purchases of natural gas, NGL's and condensate	15,449	1,464	—	16,913
Direct operating expenses	10,003	2,841	1,677	14,521
Selling, general and administrative expenses				8,534
Equity compensation expense				1,084
Depreciation, amortization and accretion expense				10,094
Total operating expenses				51,146
Gain (loss) on sale of assets, net				10
Interest expense				(5,872)
Earnings in unconsolidated affiliates				7,343
Income tax (expense) benefit				(319)
Net income (loss)				(3,964)
Less: Net income (loss) attributable to noncontrolling interests				(13)
Net income (loss) attributable to the Partnership				$(3,951)
Segment gross margin (a)	$15,730	$ 8,755	$ 3,071	$27,556

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	Three months ended March 31, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$48,449	$ 11,748	$ 4,265	$64,462
Gain (loss) on commodity derivatives, net	147	—	—	147
Total revenue	48,596	11,748	4,265	64,609
Operating expenses:				
Purchases of natural gas, NGL's and condensate	27,319	1,659	—	28,978
Direct operating expenses	9,092	3,180	1,595	13,867
Selling, general and administrative expenses				6,935
Equity compensation expense				1,698
Depreciation, amortization and accretion expense				9,689
Total operating expenses				61,167
Gain (loss) on sale of assets, net				(8)
Interest expense				(2,610)
Earnings in unconsolidated affiliate				167
Income tax (expense) benefit				(156)
Income (loss) from discontinued operations, net of tax				5
Net income (loss)				840
Less: Net income (loss) attributable to noncontrolling interests				14
Net income (loss) attributable to the Partnership				$826
Segment gross margin (a)	$21,045	$ 10,061	$ 2,670	$33,776

	March 31, 2016	December 31, 2015
Segment assets:		
Gathering and Processing	$570,993	$572,824
Transmission	139,819	133,870
Terminals	91,255	84,449
Other (b)	87,435	100,153
Total assets	$889,502	$891,296

(a) Segment gross margin for our Gathering and Processing segment consists of revenue less purchases of natural gas, NGLs and condensate and construction and operating management agreement ("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.

17. Subsequent Events

In April 2016, the Partnership announced the acquisition of interests in Gulf of Mexico midstream assets and an incremental ownership in our Delta House Investment for total consideration of approximately $225.0 million. The acquired assets include non-operated interests in the Destin and Okeanos natural gas pipelines and Tri-states and Wilprise NGL pipelines with total capacity

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of 1.2 Bcf/d and 120,000 Bbl/d, respectively. The Partnership also acquired an operating majority interest in approximately 200-miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines as well as an additional one percent non-operated indirect interest in Delta House, increasing the Partnership's total Delta House Investment to approximately 13.9%.

These acquisitions were funded through the issuance of 8,571,429 shares of newly-designated Series C Preferred Units representing limited partnership interests in the Partnership and a warrant to purchase 800,000 common units (subject to adjustment) to an affiliate of ArcLight Capital Partners, LLC, which controls our General Partner, initially estimated to have a fair value of approximately $120.0 million, and additional borrowings under our credit facility of approximately $105.0 million.

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

The following management's 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 on Form 10-Q ("Form 10-Q") 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, 2015 included in our Annual Report on Form 10-K (“Annual Report”) that was filed with the Securities and Exchange Commission ("SEC") on March 7, 2016. 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 generate sufficient cash from operations to pay distributions to unitholders;
- our ability to maintain compliance with financial covenants and ratios in our credit facility;
- the timing and extent of changes in natural gas, crude oil, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for our services;
- the level and success of natural gas and crude oil drilling by producers around our assets and our success in connecting natural gas and crude oil supplies to our gathering and processing systems;
- our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions;
- our dependence on a relatively small number of customers for a significant portion of our gross margin and the financial viability of certain of those customers;
- 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;
- our ability to successfully balance our purchases and sales of natural gas;
- the demand for NGL products by the petrochemical, refining or other industries;
- severe weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects;

- our management's history and experience with certain aspects of our business and our ability to hire as well as retain qualified personnel to execute our business strategy;
- our ability to remediate any material weakness in internal control over financial reporting;
- 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 the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance;
- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- the amount of collateral required to be posted from time to time in our transactions; and

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- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks.

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 securities laws, 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; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products, all through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines, three marine terminal sites and one crude oil pipeline. We also own a 66.7% non-operated interest in Main Pass Oil Gathering Company ("MPOG"), a crude oil gathering and processing system; a 50% undivided, non-operated interest in the Burns Point Plant, a natural gas processing plant; a 47% non-operated interest in Mesquite, an off-spec condensate fractionation project; and, a 12.9% non-operated indirect interest in Delta House, a floating production system platform and related pipeline infrastructure. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas and the Gulf of Mexico, provide critical infrastructure that links producers of natural gas, crude oil, 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 1.8 million barrels of storage capacity across three marine terminal sites.

Financial highlights for the three months ended March 31, 2016, include the following:

- Gross margin decreased to $27.6 million, or a decrease of 18.3%, as compared to the same period in 2015 primarily due to lower average throughput volumes and average realized prices associated with our Gathering and Processing segment;

- Adjusted EBITDA increased to $20.3 million, or an increase of 30.1%, as compared to the same period in 2015 primarily due to distributions from our initial investment in Delta House;

- We distributed $15.0 million to our limited partner common unitholders, or $0.4725 per unit;

Operational highlights for the three months ended March 31, 2016, 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 89.9% compared to 85.2% for the same period in 2015;

- Average gross NGL production totaled 183.8 Mgal/d, representing a 85.3 Mgal/d decrease compared to the same period in 2015;

- Average condensate production totaled 80.1 Mgal/d, representing a 19.0 Mgal/d decrease compared to the same period in 2015;

- Throughput volumes attributable to the Partnership totaled 1,028.3 MMcf/d, representing a 154.8 MMcf/d decrease compared to the same period in 2015; and

- Contracted capacity for our Terminals segment averaged 1,519,300 barrels, representing a 10.2% increase compared to the same period in 2015.

Recent Developments

Our business objectives continue to focus on maintaining stable cash flows from our existing assets and executing on growth opportunities to increase our long-term cash flows. We believe the key elements to stable cash flows are the diversity of our asset

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portfolio and our fee-based business which represents a significant portion of our estimated margins, the objective of which is to protect against downside risk in our cash flows.

Commodity Prices

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $46.03 per barrel to a low of $26.21 per barrel from January 1, 2016 through May 3, 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $2.47 per MMBtu to a low of $1.64 per MMBtu from January 1, 2016 through May 3, 2016. During 2016, we entered into commodity contracts with existing counterparties to hedge our 2016 exposure to commodity prices.

Fluctuations in energy prices, like the recent declines in commodity prices of crude oil and natural gas, can also greatly affect the development of new crude oil and natural gas reserves. Further declines in commodity prices of crude 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 continued or further reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of commodity prices on our operations. If commodity prices continue to remain depressed as they did in 2015 and through 2016 to date, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants and ratios under our Credit Agreement (as defined herein), 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 impairments of our long-lived assets, goodwill, or intangible assets.

Counterparty exposure

Certain customers and producers within our Gathering and Processing and Transmission segments may be highly leveraged or under-capitalized and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. Any material nonpayment or nonperformance by any of our key customers or purchasers could have a material adverse effect on our revenue, gross margin and cash flows and our ability to make cash distributions to our unitholders. For the three months ended March 31, 2016, our Gathering and Processing segment derived 14% of its revenue from each of ConocoPhilips Company and Penn Virginia Oil & Gas, LP. For the three months ended March 31, 2016, our Transmission segment derived 20% and 15% of its revenue from Superior Natural Gas Corporation and ConocoPhilips Company, respectively, who were the two largest purchasers of natural gas and transmission capacity.

Capital Markets

Volatility in the capital markets continues to impact our operations in multiple ways, including limiting our producers' ability to finance their drilling and workover programs and limiting our ability to fund drop downs, organic growth projects and acquisitions.

Subsequent Events

Acquisition of interests in Gulf of Mexico midstream assets

In April, 2016, the Partnership announced the acquisition of interests in Gulf of Mexico midstream assets and an incremental ownership in our Delta House Investment for total consideration of approximately $225.0 million. The acquired assets include non-operated interests in the Destin and Okeanos natural gas pipelines and Tri-states and

Wilprise NGL pipelines with total capacity of 1.2 Bcf/d and 120,000 Bbl/d, respectively. The Partnership also acquired an operating majority interest in approximately 200-miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines as well as an additional one percent non-operated indirect interest in Delta House, increasing the Partnership's total Delta House Investment to approximately 13.9 percent.

These acquisitions were funded through the issuance of 8,571,429 shares of newly-designated Series C Preferred Units representing limited partnership interests in the Partnership and a warrant to purchase 800,000 common units (subject to adjustment) to an affiliate of ArcLight Capital Partners, LLC, which controls our General Partner, initially estimated to have a fair value of approximately $120.0 million, and additional borrowings under our credit facility of approximately $105.0 million.

Distribution

On April 25, 2016, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per unit for the first quarter ended March 31, 2016, or $1.65 per unit on an annualized basis and equal to the Minimum Quarterly Distribution as defined in the Partnership Agreement. The distribution will be paid on May 13, 2016, to unitholders of

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record as of the close of business on May 4, 2016. The decision to lower the quarterly distribution was based primarily on the significant dislocation in the public equity markets and will provide us with incremental liquidity to fund growth opportunities or reduce borrowings on the credit facility.

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 crude oil, which include transporting raw natural gas and crude oil 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, crude oil, 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 (“LDCs”), utilities and industrial, commercial and power generation customers.

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

Gathering and Processing Segment

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

- 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, 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. Our POP arrangements also often contain a fee-based component.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas and crude oil 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 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

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Results of operations from the 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.

Terminals Segment

Our Terminals segment provides above-ground leasable 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, throughput fees charged to our customers when their products are either received or disbursed and other fee-based charges associated with ancillary services provided to our customers, 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 March 31, 2016 and 2015, $24.8 million and $28.8 million, or 89.9% and 85.2%, 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 three months ended March 31, 2016 and 2015 (in thousands):

	For the Three Months Ended March 31, 2016			For the Three Months Ended March 31, 2015		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gathering and Processing						
Fee-based	$10,366	65.9	%	$9,744	46.3	%
Fixed margin	2,596	16.5	%	6,271	29.8	%
Percent-of-proceeds	2,768	17.6	%	5,030	23.9	%
Total	$15,730	100.0	%	$21,045	100.0	%

Transmission						
Firm transportation	$3,826	43.7	%	$3,300	32.8	%
Interruptible transportation	4,929	56.3	%	6,077	60.4	%
Fixed margin	—	—	%	684	6.8	%
Total	$8,755	100.0	%	$10,061	100.0	%
Terminals						
Firm storage	$3,071	100.0	%	$2,670	100.0	%
Total	$3,071	100.0	%	$2,670	100.0	%

Cash distributions derived from our unconsolidated affiliates amounted to $13.5 million and $1.0 million for the three months ended March 31, 2016 and 2015, respectively, and are primarily generated from fee-based gathering and processing arrangements.

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, crude oil, NGLs and condensate to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas, crude oil, NGLs and condensate 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, crude oil, NGLs and condensate that has been released from other commitments and iv) the volume of natural gas, crude oil, 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 maintain current throughput volumes and pursue new supply opportunities.

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines. Substantially all of our 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 maintain current throughput volumes and pursue new shipper opportunities.

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed, and other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating, truck weighing, etc.

Storage Utilization

Storage utilization is a metric that we use to evaluate the performance of our Terminals segment. We define storage utilization as the percentage of the contracted capacity in barrels compared to the design capacity of the tank.

Segment Gross Margin and Gross Margin

Segment gross margin and 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, crude oil, 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 treatment of natural gas and crude oil and from the sale of natural gas, crude oil, NGLs and condensate resulting from gathering and processing activities under fixed-margin and percent-of-proceeds arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to percent-of-proceeds arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

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 directly comparable to gross margin is net income (loss) attributable to the Partnership.

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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 flow from operations to make cash distributions to our unit holders and General Partner and its affiliates;
- 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 (loss) attributable to the Partnership, plus interest expense, income tax expense, depreciation, amortization and accretion expense, certain non-cash charges such as non-cash equity compensation expense, unrealized losses on commodity derivative contracts, debt issuance costs, return of capital from unconsolidated affiliates, transaction expenses and selected charges that are unusual or nonrecurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, 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, segment gross margin and Adjusted EBITDA are performance measures that are considered 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 gross margin, segment 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. Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies in our industry.

The following tables reconcile the non-GAAP financial measures of gross margin and Adjusted EBITDA used by management to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for the three months ended March 31, 2016 and 2015 (in thousands):

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	Three months ended March 31, 2016	2015
Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership:		
Gathering and processing segment gross margin	$15,730	$21,045
Transmission segment gross margin	8,755	10,061
Terminals segment gross margin (a)	3,071	2,670
Total Gross Margin	27,556	33,776
Plus:		
Gain (loss) on commodity derivatives, net	(103)	147
Earnings in unconsolidated affiliates	7,343	167
Less:		
Direct operating expenses (a)	12,844	12,272
Selling, general and administrative expenses	8,534	6,935
Equity compensation expense	1,084	1,698
Depreciation, amortization and accretion expense	10,094	9,689
(Gain) loss on sale of assets, net	(10)	8
Interest expense	5,872	2,610
Other, net (b)	23	(113)
Income tax expense (benefit)	319	156
(Income) loss from discontinued operations, net of tax	—	(5)
Net income (loss) attributable to noncontrolling interest	(13)	14
Net income (loss) attributable to the Partnership	$(3,951)	$826

(a) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $10.0 million and $9.1 million, respectively, and Transmission segment direct operating expenses of $2.8 million and $3.2 million, respectively, for the three months ended March 31, 2016 and 2015. Direct operating expenses related to our Terminals segment of $1.7 million and $1.6 million for the three months ended March 31, 2016 and 2015 are included within the calculation of Terminals segment gross margin, respectively.

(b) Other, net includes realized gain (loss) on commodity derivatives of $0.0 million and $0.1 million, respectively, and COMA income of less than $0.1 million and $0.3 million, respectively, for the three months ended March 31, 2016 and 2015.

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	Three months ended March 31,	
	2016	2015
Reconciliation of Adjusted EBITDA to Net income (loss) attributable to the Partnership:		
Net income (loss) attributable to the Partnership	$(3,951)	$826
Add:		
Depreciation, amortization and accretion expense	10,094	9,689
Interest expense	4,692	2,384
Debt issuance costs	135	230
Unrealized (gain) loss on derivatives, net	833	(55)
Non-cash equity compensation expense	1,084	1,698
Transaction expenses	876	43
Income tax expense (benefit)	319	160
Proceeds from equity method investments, return of capital	6,172	833
Deduct:		
COMA income	(23)	252
OPEB plan net periodic benefit	4	3
Gain (loss) on sale of assets, net	10	(8)
Adjusted EBITDA	$20,263	$15,561

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 decreased by $6.2 million, or 18.3%, for the three months ended March 31, 2016 as compared to the same period in 2015. For the three months ended March 31, 2016, the decrease in gross margin was primarily due to lower gross margin of $5.3 million associated with our Gathering and Processing segment. The lower margin associated with our Gathering and Processing segment was the result of a decrease in average throughput volumes of 10.3% and lower average realized prices related to natural gas, NGLs, and condensate of 34.8%, 38.3%, and 40.0%, respectively.

For the three months ended March 31, 2016, Adjusted EBITDA increased $4.7 million, or 30.1%, compared to the same period in 2015. The increase is primarily related to higher cash distributions derived from our unconsolidated affiliates of $12.5 million primarily due to the September 2015 investment in Delta House. These increases were partially offset by lower gross margin of $6.2 million and higher direct operating expenses and selling, general and administrative expenses, period over period.

We distributed $15.0 million to holders of our common units, or $0.4725 per unit, during the three months ended March 31, 2016. The distribution to holders of our common units of $0.4725 per unit paid during the current quarter is equal to the distribution paid during the three months ended March 31, 2015.

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 March 31, 2016	2015
Statement of Operations Data:		
Revenue	$46,123	$64,462
Gain (loss) on commodity derivatives, net	(103)	147
Total revenue	46,020	64,609
Operating expenses:		
Purchases of natural gas, NGLs and condensate	16,913	28,978
Direct operating expenses	14,521	13,867
Selling, general and administrative expenses	8,534	6,935
Equity compensation expense (a)	1,084	1,698
Depreciation, amortization and accretion expense	10,094	9,689
Total operating expenses	51,146	61,167
Gain (loss) on sale of assets, net	10	(8)
Operating income (loss)	(5,116)	3,434
Other income (expense):		
Interest expense	(5,872)	(2,610)
Earnings in unconsolidated affiliates	7,343	167
Net income (loss) before income tax (expense) benefit	(3,645)	991
Income tax (expense) benefit	(319)	(156)
Net income (loss) from continuing operations	(3,964)	835
Income (loss) from discontinued operations, net of tax	—	5
Net income (loss)	(3,964)	840
Net income (loss) attributable to noncontrolling interests	(13)	14
Net income (loss) attributable to the Partnership	$(3,951)	$826
Other Financial Data:		
Gross margin (b)	$27,556	$33,776
Adjusted EBITDA (b)	$20,263	$15,561

(a) Primarily represents non-cash costs related to our Long-Term Incentive Plans.

(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 March 31, 2016 Compared to Three Months Ended March 31, 2015

Total Revenue. Our total revenue for the three months ended March 31, 2016 was $46.0 million compared to $64.6 million for the three months ended March 31, 2015. This decrease of $18.6 million was primarily due to the following:

- a decrease in NGL revenues of $7.1 million due to lower gross NGL production volumes of 85.3 Mgal/d from our Gathering and Processing segment and lower realized NGL prices of $0.37/gal, which is a decrease of $0.23/gal period over period,
- a decrease in condensate revenues of $6.2 million due to lower realized condensate prices of $0.57/gal, which is a decrease of $0.38/gal, or 40.0%, period over period, and lower condensate production of 19.0 Mgal/d from our Gathering and Processing segment,
-

- a decrease in natural gas revenue of $4.9 million due to lower realized natural gas prices of $2.21/Mcf, which is a decrease of $1.18/Mcf, or 34.8% period over period,
- a decrease in fee-based revenues of $0.4 million primarily due to lower average throughput volumes in our Gathering and Processing segment of 38.5 MMcf/d, or 10.3% period over period,
- a decrease in transportation revenue of $0.1 million due to lower throughput volumes in our Transmission segment, and

- a loss on commodity derivatives, net of $0.1 million compared to a gain on commodity derivatives, net of $0.1 million for the comparable quarter in 2015.

These decreases were partially offset by 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.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended March 31, 2016 were $16.9 million compared to $29.0 million for the three months ended March 31, 2015. This decrease of $12.1 million was due to lower NGL and natural gas purchases of $7.2 million and $5.9 million, respectively. The decrease in NGL and natural gas purchases are the result of lower NGL and natural gas prices and lower NGL and natural gas volumes related to our Gathering and Processing segment.

Gross Margin. Gross margin for the three months ended March 31, 2016 was $27.6 million compared to $33.8 million for the three months ended March 31, 2015. This decrease of $6.2 million was primarily due to a decrease in segment gross margin in our Gathering and Processing segment of $5.3 million, as a result of lower NGL and condensate production of 85.3 Mgal/d and 19.0 Mgal/d, respectively, and lower average throughput volumes of 38.5 MMcf/d, as well as lower segment gross margin in our Transmission segment of $1.3 million as a result of a decrease in average throughput volumes. These decreases were partially offset by higher segment gross margin in our Terminals segment of $0.4 million.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2016 were $14.5 million compared to $13.9 million in the three months ended March 31, 2015. This increase of $0.6 million was primarily due to $0.9 million of costs associated with the Bakken crude oil system that commenced operations during October of 2015, partially offset by the timing of activities associated with our integrity management and maintenance programs and lower insurance premiums.

Selling, General and Administrative Expenses (SG&A). SG&A expenses for the three months ended March 31, 2016 were $8.5 million compared to $6.9 million for the three months ended March 31, 2015. This increase of $1.6 million was primarily due to the accrual of $0.7 million of severance costs related to the consolidation of our corporate offices, anticipated to be completed by the fourth quarter of 2016. SG&A expenses were also higher due to an increase in information and technology maintenance costs primarily related to systems that were implemented in the prior year.

Equity Compensation Expense. Equity compensation expense related to our Long-Term Incentive Plan for the three months ended March 31, 2016 was $1.1 million compared to $1.7 million for the three months ended March 31, 2015. This decrease of $0.6 million was primarily due to a one-time award made to certain executives in lieu of cash payments related to our short-term incentive compensation plan during the first quarter of 2015.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended March 31, 2016 was $10.1 million compared to $9.7 million for the three months ended March 31, 2015. This increase of $0.4 million was primarily due to incremental depreciation of fixed assets related to our Bakken system which began operations in October of 2015.

Interest Expense. Interest expense for the three months ended March 31, 2016 was $5.9 million compared to $2.6 million for the three months ended March 31, 2015. This increase of $3.3 million was primarily due to higher outstanding borrowings under the Credit Agreement and an increase in our weighted average interest rate of 1.76%.

Earnings in unconsolidated affiliates. Earnings in unconsolidated affiliates for the three months ended March 31, 2016 was $7.3 million compared to $0.2 million for the three months ended March 31, 2015. This increase of $7.1 million was due to incremental earnings of $7.1 million related to our initial investment in Delta House, which was acquired in September 2015.

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).

	Three months ended March 31,	
	2016	2015
Segment Financial and Operating Data:		
Gathering and Processing segment		
Financial data:		
Revenue	$31,148	$48,449
Gain (loss) on commodity derivatives, net	(103)	147
Total revenue	31,045	48,596
Purchases of natural gas, NGLs and condensate	15,449	27,319
Direct operating expenses	10,003	9,092
Other financial data:		
Segment gross margin	$15,730	$21,045
Operating data:		
Average throughput (MMcf/d)	333.6	372.1
Average plant inlet volume (MMcf/d) (a)	103.2	136.1
Average gross NGL production (Mgal/d) (a)	183.8	269.1
Average gross condensate production (Mgal/d) (a)	80.1	99.1
Average realized prices:		
Natural gas ($/Mcf)	$2.21	$3.39
NGLs ($/gal)	$0.37	$0.60
Condensate ($/gal)	$0.57	$0.95

(a) Excludes volumes and gross production under our elective processing arrangements.

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Revenue. Segment total revenue for the three months ended March 31, 2016 was $31.0 million compared to $48.6 million for the three months ended March 31, 2015. This decrease of $17.6 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 34.8%, 38.3%, and 40.0%, respectively,
- lower average throughput volumes of 38.5 MMcf/d, period over period, primarily due to lower inlet volumes at the Burns Point plant, and
- lower average NGL and condensate production of 85.3 Mgal/d and 19.0 Mgal/d, respectively, primarily due to a decrease in off-spec NGL and condensate volumes received and processed at our the Longview system.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended March 31, 2016 were $15.4 million compared to $27.3 million for the three months ended March 31, 2015. This decrease of $11.9 million was due to lower purchase costs associated with natural gas, NGLs and condensate, period over period. The lower purchase costs were the result of lower realized natural gas, NGL and condensate prices, as well as lower NGL and condensate purchased volumes at the Longview system, period over period.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2016 was $15.7 million compared to $21.0 million for the three months ended March 31, 2015. This decrease of $5.3 million was primarily due to lower gross margin of $4.1 million related to the Longview, Chapel Hill, and Danville systems as a result of the lower commodity prices and production volumes as discussed above, as well as lower gross margin of $1.4 million at our Lavaca System due to contractually lower compression fees and lower contracted condensate sales.

These decreases in segment gross margin, as well as those on our other Gathering and Processing segment assets that resulted from lower commodity prices and volumes, were partially offset by incremental gross margin of $1.1 million on the Bakken crude oil system which commenced operations in October of 2015.

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Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2016 were $10.0 million compared to $9.1 million for the three months ended March 31, 2015. This increase of $0.9 million was primarily due to direct labor and benefits associated with the Bakken crude oil system that commenced operations during October of 2015.

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 March 31,	
	2016	2015
Segment Financial and Operating Data:		
Transmission segment		
Financial data:		
Total revenue	$10,227	$11,748
Purchases of natural gas, NGLs and condensate	1,464	1,659
Direct operating expenses	2,841	3,180
Other financial data:		
Segment gross margin	$8,755	$10,061
Operating data:		
Average throughput (MMcf/d)	694.7	811.0
Average firm transportation - capacity reservation (MMcf/d)	744.4	695.0
Average interruptible transportation - throughput (MMcf/d)	400.5	445.6

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Revenue. Segment total revenue for the three months ended March 31, 2016 was $10.2 million compared to $11.7 million for the three months ended March 31, 2015. This decrease of $1.5 million in segment revenue was primarily due to lower average throughout volumes of 116.3 MMcf/d primarily attributable to our Midla and High Point systems.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended March 31, 2016 of $1.5 million was consistent to $1.7 million for the three months ended March 31, 2015.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2016 was $8.8 million compared to $10.1 million for the three months ended March 31, 2015. This decrease of $1.3 million was primarily due to the lower average throughput volumes of 116.3 MMcf/d, or 14.3%, noted above, and lower interruptible transportation margins, period over period.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2016 were $2.8 million compared with the $3.2 million for the three months ended March 31, 2015. This decrease of $0.4 million was primarily related to the timing of activities associated with our integrity management and maintenance program and lower insurance premiums, period over period.

Terminals Segment

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

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	Three months ended March 31,	
	2016	2015
Segment Financial and Operating Data:		
Terminals segment		
Financial data:		
Total revenue	$4,748	$4,265
Direct operating expenses	1,677	1,595
Other financial data:		
Segment gross margin	$3,071	$2,670
Operating data:		
Contracted Capacity (Bbls)	1,519,300	1,378,467
Design Capacity (Bbls)	1,800,800	1,675,019
Storage utilization (a)	84.4 %	82.3 %

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

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Revenue. Segment total revenue for the three months ended March 31, 2016 was $4.7 million compared to $4.3 million for the three months ended March 31, 2015. The increase of $0.4 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at the Harvey and Westwego terminals and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2016 of $1.7 million was consistent with the $1.6 million of direct operating expenses for the three months ended March 31, 2015.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2016 was $3.1 million compared to $2.7 million for the three months ended March 31, 2015. The increase of $0.4 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.

Our principal sources of liquidity include borrowings under our Credit Agreement, issuance of equity in the capital markets or through private transactions, and financial support from ArcLight Capital Partners, LLC, who controls our General Partner. In addition, we may seek to raise capital through the issuance of unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that cash generated from our operating activities 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 four quarters. 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 non-essential capital expenditures, direct operating expenses and selling, general and administrative expenses, as necessary, and our Partnership Agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations.
Our liquidity for the three months ended March 31, 2016 was impacted by the conversion of the Series B Units into common units on February 1, 2016, which resulted in an increase in the total cash distributions paid to common unit

holders during the current quarter. Our liquidity in that period was also impacted by borrowings under our Credit Agreement to fund ongoing organic capital growth projects.

Changes in natural gas, crude oil, 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. During 2015, we 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

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about Market Risk" and Part I, Item 3 of this 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 natural gas and crude oil 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. As of March 31, 2016, we have not been required to post collateral with our counterparties.

Our Credit Facility

On September 18, 2015, the Partnership entered into the First Amendment to the Partnership's Credit Agreement, which provides for maximum borrowings equal to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million subject to lender approval. The Credit Agreement contains certain financial covenants, including i) a consolidated leverage ratio that requires our indebtedness not to exceed 4.75 times adjusted consolidated EBITDA (as defined in the Credit Agreement) for the prior twelve month period (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant may be increased to 5.25 times adjusted consolidated EBITDA), and ii) a minimum interest coverage ratio that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by at least 2.50 times. The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $750.0 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 lien on substantially all of our assets. 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 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 March 31, 2016 our consolidated total leverage was 5.17 and our interest coverage ratio was 6.74, 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 twelve month period ended March 31, 2016, as result of the initial investment in Delta House in September 2015. The maximum permitted consolidated total leverage ratio will revert to 4.75 for the quarter ended June 30, 2016. As of March 31, 2016, we had approximately $549.4 million of outstanding borrowings under the $750.0 million Credit Agreement.

At March 31, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $1.8 million.

As of March 31, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions, or drop down transactions, as well as the associated financing for such initiatives. If required, ArcLight Capital Partners, LLC, which controls the General Partner of the Partnership, has agreed to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through December 31, 2016.

Working Capital

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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 $11.7 million at March 31, 2016, compared with a working capital deficit of $10.1 million at December 31, 2015.

Cash Flows

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

	Three months ended March 31,	
	2016	2015
Net cash provided by (used in):		
Operating activities	$8,217	$9,102
Investing activities	(15,415)	(28,656)
Financing activities	7,198	19,055

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Operating Activities. Net cash provided by operating activities was $8.2 million for the three months ended March 31, 2016 compared to $9.1 million for the three months ended March 31, 2015. Net cash provided by operating activities for the three months ended March 31, 2016 decreased by $0.9 million period over period primarily due to a decrease in gross margin of $6.2 million, increases in direct operating expenses and selling, general and administrative expenses of $0.6 million and $1.6 million, respectively, and an increase in interest expense of $3.3 million due to a higher outstanding borrowings.

These decreases in operating cash flows were partially offset by favorable changes in operating assets and liabilities of $3.0 million, and an increase in earnings from unconsolidated affiliates of $7.2 million due to the acquisition of our initial 12.9% indirect interest in Delta House in September 2015.

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. Average throughput volume changes also impact cash flow, but have not been as volatile as commodity prices. Another source of variability in our cash flows from operating activities is fluctuation in commodity prices, which we partially mitigated by entering into commodity derivatives.

Investing Activities. Net cash used in investing activities was $15.4 million for the three months ended March 31, 2016 compared to $28.7 million for the three months ended March 31, 2015. Cash used in investing activities for the three months ended March 31, 2016 decreased by $13.3 million primarily due to lower capital expenditures of $20.9 million as a result of a decrease in growth capital projects in process, period over period, as well as higher cash distributions received from unconsolidated affiliates in excess of cumulative earnings of $5.3 million.

These decreases in cash used in investing activities were partially offset by higher cash disbursements of $3.5 million related to equity method investments period over period, the return of restricted cash in the first quarter of 2015 of $6.5 million, and cash proceeds on the disposition of assets of $2.8 million received during the first quarter of 2015.

Financing Activities. Net cash provided by financing activities was $7.2 million for the three months ended March 31, 2016 compared to $19.1 million for the three months ended March 31, 2015. Cash provided by financing activities for the three months ended March 31, 2016 decreased by $11.9 million which was primarily due to the issuance of Series A-2 units for gross proceeds of $20.0 million in the first quarter of 2015. This decrease of the cash proceeds received period over period, was partially offset by higher net borrowings on our Credit Agreement of $10.4 million.

Off-Balance Sheet Arrangements

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We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At March 31, 2016, 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 March 31, 2016, our off-balance sheet arrangements did not change materially from those listed in "Contractual Obligations" within Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report filed on March 7, 2016.

Capital Requirements

The energy business is 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) made to maintain our operating income or operating capacity; or

- expansion capital expenditures, incurred for acquisitions of capital assets or capital improvements that we expect will increase our operating income or operating capacity over the long term.

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 three months ended March 31, 2016, capital expenditures totaled $18.1 million, including expansion capital expenditures of $17.5 million, maintenance capital expenditures of $0.4 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 $0.2 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 up to $7.2 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 April 25, 2016, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per unit for the first quarter ended March 31, 2016, or $1.65 per unit on an annualized basis. The cash distribution is expected to be paid on May 13, 2016, to unitholders of record as of the close of business on May 4, 2016.

Critical Accounting Policies

There were no changes to our critical accounting policies from those disclosed in our Annual Report filed on March 7, 2016.

Recent Accounting Pronouncements

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, please refer to Note 1 - Organization, Basis of Presentation and Summary of Significant Accounting Policies in Part I, Item 1 of this Quarterly Report, which is incorporated herein by reference.

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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 are exposed to the impact of market fluctuations in the prices of natural gas, crude oil, NGLs and condensate in our Gathering and Processing segment. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas, crude oil and NGL prices are impacted by changes in the supply and demand for these energy commodities, as well as market uncertainty. For a discussion of the volatility of natural gas, crude oil, and NGL prices, please refer to "Item 1A. Risk Factors" of our Annual Report. Adverse effects on our cash flow from reductions in natural gas, crude oil and NGL prices could adversely affect our operating cash flows and our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets, and the use of derivative contracts. Our overall direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our current contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing.

To minimize the effect of commodity prices 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, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns 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. Historically, the commodity derivatives are in the form of swaps and collars.

We enter into commodity contracts with counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of March 31, 2016, we have not been required to post collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

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 risk by our counterparties on our open derivative contracts. Certain of our counterparties to our commodity swap contracts are investment-grade rated financial institutions and therefore we do not expect significant exposure to non-performance risk. 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 4 "Derivatives" for further details.

As of March 31, 2016, we have hedged approximately 43% of our expected exposure to NGL prices and 62% of our expected exposure to oil prices through the end of 2016.

The table below sets forth certain information regarding the financial instruments used to hedge our commodity price risk as of March 31, 2016:

Commodity	Instrument	Volumes (a)	Weighted Average Price	Period

					Fair value at March 31, 2016 (in thousands)
NGLs (gal)	Swaps	(6,345,350)	$0.62	April 2016 - December 2016	$ (132)
Oil (Bbl)	Swaps	(31,150)	$42.41	April 2016 - December 2016	29
					$ (103)

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

Interest Rate Risk

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During the three months ended March 31, 2016, we had exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. To manage the impact of the interest rate risk associated with our Credit Agreement, we enter into interest rate swaps from time to time, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows.

On March 2, 2016, we entered into interest rate swaps with a notional amount of $200.0 million that will expire in September 2019.

The credit markets have recently experienced 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. For example, on December 16, 2015, the Federal Open Market Committee raised the target range for the federal funds rate by 0.25%. Future 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 $1.4 million for the three months ended March 31, 2016.

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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.

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, as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2016, the end of the period covered by this report, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended March 31, 2016 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

In addition to the information about our business, financial conditions and results of operations set forth in this Quarterly Report, careful consideration should be given to the risk factors discussed under the caption “Risk Factors” in Part I, Item 1A of our Annual Report and below in this Quarterly Report.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, we either consider our customers creditworthy or require those who are not creditworthy to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies will not completely eliminate customer and counterparty credit risk. Our customers and counterparties include entities whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities. The current low commodity price environment has negatively impacted many oil and gas companies causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with the customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, results of operations, cash flows and financial conditions. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

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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	Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated April 25, 2016 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
3.3	Certificate of Formation of American Midstream GP, LLC (filed as Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.4	Third Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on May 6, 2016).
31.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Daniel C. Campbell, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Daniel C. Campbell, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**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
**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: May 9, 2016

AMERICAN MIDSTREAM PARTNERS, LP

By:	American Midstream GP, LLC, its general partner
By:	/s/ Lynn L. Bourdon III
Name:	Lynn L. Bourdon III
Title:	Chairman, President and Chief Executive Officer of American Midstream Partners, LP (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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