American Midstream Partners, LP
Form 10-Q
August 08, 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
June 30, 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 31,154,636 common units, 9,797,342 Series A Units, and 8,571,429 Series C Units of American Midstream Partners, LP outstanding as of August 5, 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.
Bcf /d	Billion cubic feet per day.
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) are the combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Throughput	

The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

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

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

	June 30, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$754	$ —
Accounts receivable	8,875	3,181
Unbilled revenue	18,817	15,559
Risk management assets	944	365
Other current assets	13,348	10,094
Total current assets	42,738	29,199
Property, plant and equipment, net	683,109	648,013
Goodwill	16,262	16,262
Intangible assets, net	98,790	100,965
Investment in unconsolidated affiliates	295,572	82,301
Other assets, net	14,497	14,556
Total assets	$1,150,968	$ 891,296
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$4,811	$ 4,667
Accrued gas purchases	9,566	7,281
Accrued expenses and other current liabilities	37,077	25,035
Current portion of long-term debt	731	2,338
Risk management liabilities	832	—
Total current liabilities	53,017	39,321
Risk management liabilities	2,556	—
Asset retirement obligations	43,430	28,549
Other liabilities	399	1,001
Long-term debt	672,400	525,100
Deferred tax liability	6,661	5,826
Total liabilities	778,463	599,797
Commitments and contingencies (See Note 16)		
Convertible preferred units		
Series A convertible preferred units (9,797 thousand and 9,210 thousand units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively)	176,335	169,712
Series C convertible preferred units (8,571 thousand and zero units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively)	116,390	—
Equity and partners' capital		
General Partner Interests (664 thousand and 536 thousand units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively)	(100,624)	(104,853)
Limited Partner Interests (31,146 thousand and 30,427 thousand units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively)	172,840	188,477
Series B convertible units (zero and 1,350 thousand units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively)	—	33,593
Accumulated other comprehensive income (loss)	75	40

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Total partners’ capital	72,291	117,257
Noncontrolling interests	7,489	4,530
Total equity and partners' capital	79,780	121,787
Total liabilities, equity and partners' capital	$1,150,968	$891,296

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

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

	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Revenue	$56,148	$67,198	$102,271	$131,660
Gain (loss) on commodity derivatives, net	(766)	311	(869)	458
Total revenue	55,382	67,509	101,402	132,118
Operating expenses:				
Purchases of natural gas, NGLs and condensate	22,102	33,334	39,014	62,311
Direct operating expenses	16,191	13,967	30,712	27,834
Selling, general and administrative expenses	11,432	5,571	19,966	12,506
Equity compensation expense	1,025	550	2,109	2,248
Depreciation, amortization and accretion expense	10,903	9,250	20,997	18,939
Total operating expenses	61,653	62,672	112,798	123,838
Gain (loss) on sale of assets, net	80	(2,970)	90	(2,978)
Operating income (loss)	(6,191)	1,867	(11,306)	5,302
Other income (expense):				
Interest expense	(8,507)	(3,556)	(14,379)	(6,166)
Earnings in unconsolidated affiliates	11,647	4	18,990	171
Net income (loss) before income tax (expense) benefit	(3,051)	(1,685)	(6,695)	(693)
Income tax (expense) benefit	(540)	(317)	(860)	(473)
Net income (loss) from continuing operations	(3,591)	(2,002)	(7,555)	(1,166)
Income (loss) from discontinued operations, net of tax	—	(31)	—	(26)
Net income (loss)	(3,591)	(2,033)	(7,555)	(1,192)
Net income (loss) attributable to noncontrolling interests	992	32	979	46
Net income (loss) attributable to the Partnership	$(4,583)	$(2,065)	$(8,534)	$(1,238)
General Partner's Interest in net income (loss)	$(61)	$(25)	$(113)	$(14)
Limited Partners' Interest in net income (loss)	$(4,522)	$(2,040)	$(8,421)	$(1,224)
Distribution declared per common unit (a)	$0.4125	$0.4725	$0.8850	$0.9450
Limited partners' net income (loss) per common unit (See Note 13):				
Basic and diluted	$(0.36)	$(0.35)	$(0.69)	$(0.53)
Weighted average number of common units outstanding:				
Basic and diluted	30,949	22,757	30,884	22,730

(a) Distributions declared and paid each quarter related to prior periods' quarter.

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 (Loss)
(Unaudited, in thousands)

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$(3,591)	$(2,033)	$(7,555)	$(1,192)
Unrealized gain (loss) on postretirement benefit plan assets and liabilities	21	(23)	35	(34)
Comprehensive income (loss)	(3,570)	(2,056)	(7,520)	(1,226)
Less: Comprehensive income (loss) attributable to noncontrolling interests	992	32	979	46
Comprehensive income (loss) attributable to the Partnership	$(4,562)	$(2,088)	$(8,499)	$(1,272)

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 Interests	Limited Partner Interests	Series B Convertible Units	Accumulated Other Comprehensive Income (Loss)	Total Partners' Capital	Noncontrolling Interest
Balances at December 31, 2014	$(2,450)	$294,695	$ 32,220	$ 2	$324,467	$ 4,717
Net income (loss)	(14)	(1,224)	—	—	(1,238)	46
Issuance of Series B units	—	—	833	—	833	—
Unitholder contributions	376	—	—	—	376	—
Unitholder distributions	(3,004)	(29,800)	—	—	(32,804)	—
Net distributions to noncontrolling interests	—	—	—	—	—	(70)
LTIP vesting	(2,178)	2,373	—	—	195	—
Tax netting repurchase	—	(725)	—	—	(725)	—
Equity compensation expense	2,052	—	—	—	2,052	—
Other comprehensive income (loss)	—	—	—	(34)	(34)	—
Balances at June 30, 2015	$(5,218)	$265,319	$ 33,053	$ (32)	$293,122	$ 4,693
Balances at December 31, 2015	$(104,853)	$188,477	$ 33,593	$ 40	$117,257	$ 4,530
Net income (loss)	(113)	(8,421)	—	—	(8,534)	979
Issuance of common units, net of offering costs	—	2,986	—	—	2,986	—
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B units	—	33,593	(33,593)	—	—	—
Issuance of Warrant	4,481	—			4,481	
Unitholder contributions	1,791	—	—	—	1,791	—
Unitholder distributions	(2,351)	(38,935)	—	—	(41,286)	—
Unitholder contribution for acquisitions	990	—	—	—	990	—
Net contributions from noncontrolling interests	—	—	—	—	—	149
Acquisition of noncontrolling interest	—	—	—	—	—	1,831
LTIP vesting	(2,107)	2,107	—	—	—	—
Tax netting repurchase	—	(150)	—	—	(150)	—
Equity compensation expense	1,538	—	—	—	1,538	—
Other comprehensive income (loss)	—	—	—	35	35	—
Balances at June 30, 2016	$(100,624)	$172,840	$ —	$ 75	$72,291	$ 7,489

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)

	Six months ended June 30,	
	2016	2015
Cash flows from operating activities		
Net income (loss)	$(7,555)	$(1,192)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	20,997	18,939
Amortization of deferred financing costs	1,030	667
Amortization of weather derivative premium	451	475
Unrealized (gain) loss on commodity derivatives, net	3,388	(213)
Non-cash compensation	2,109	2,294
Postretirement expense (benefit)	—	18
(Gain) loss on sale of assets, net	(90)	2,978
Earnings in unconsolidated affiliates	(18,990)	(171)
Distributions from unconsolidated affiliates	18,990	171
Deferred tax expense (benefit)	835	457
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	(5,694)	(1,331)
Unbilled revenue	(3,258)	5,964
Risk management assets and liabilities	(1,030)	(875)
Other current assets	1,753	1,041
Other assets, net	700	37
Accounts payable	1,136	6,200
Accrued gas purchases	2,285	(4,709)
Accrued expenses and other current liabilities	2,303	(1,293)
Asset retirement obligations	(10)	—
Other liabilities	(673)	163
Net cash provided by operating activities	18,677	29,620
Cash flows from investing activities		
Cost of acquisitions, net of cash acquired and settlements	(3,073)	7,383
Acquisition of investments in unconsolidated affiliates	(100,908)	—
Additions to property, plant and equipment	(40,242)	(79,734)
Proceeds from disposals of property, plant and equipment	137	3,876
Investment in unconsolidated affiliates	(11,444)	(626)
Distributions from unconsolidated affiliates, return of capital	16,728	1,329
Restricted cash	—	6,475
Net cash used in investing activities	(138,802)	(61,297)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	3,004	(348)
Unitholder contributions	1,791	330
Unitholder distributions	(29,964)	(24,364)
Issuance of Series A Units, net of issuance costs	—	45,000
Acquisition of noncontrolling interests	1,831	—
Net contributions from (distributions to) noncontrolling interests	149	(70)
LTIP tax netting unit repurchase	(150)	(725)

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Deferred financing costs	(1,475)	(276)
Payments on other debt	(1,607)	(2,171)
Payments on long-term debt	(64,900)	(123,650)
Borrowings on long-term debt	212,200	137,800
Net cash provided by financing activities	120,879	31,526
Net increase (decrease) in cash and cash equivalents	754	(151)
Cash and cash equivalents		
Beginning of period	—	499
End of period	$754	$348
Supplemental cash flow information		
Interest payments, net	$12,603	$5,572
Supplemental non-cash information		
(Decrease) increase in accrued property, plant and equipment	$3,221	$(16,897)
Issuance of Series C Units and Warrant in connection with the Emerald Transactions	120,000	—
Accrued and paid-in-kind unitholder distribution for Series A Units	9,073	7,607
Accrued and paid-in-kind unitholder distribution for Series C Units	2,249	—
Paid-in-kind unitholder distribution for Series B Units	—	833
Cancellation of escrow units	6,817	—
Accrued distribution from unconsolidated affiliate	4,360	—

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 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 13 gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines, three marine terminal sites and one crude oil pipeline. 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 2.2 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 GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for annual financial statements. The year-end balance sheet data was derived from consolidated audited financial statements but does not include disclosures required by GAAP for annual periods. The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the respective interim periods.

Our financial results for the three and six months ended June 30, 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 the 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

We hold various non-operated membership interests in entities that own and operate natural gas pipeline systems, NGL and crude oil pipelines in and around Louisiana, Alabama, Mississippi and the Gulf of Mexico. These non-operated membership interests 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 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 potential need for impairment. The Partnership uses evidence of a loss in value to identify if an investment has incurred an other than temporary decline.

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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. Subsequently, in April 2016, the FASB issued ASU 2016-10, Revenue from Contracts with Customers (Topic 606)-Identifying Performance Obligations and Licensing as further clarification on identifying performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606)-Narrow-Scope Improvements and Practical Expedients, as clarifying guidance on specific narrow scope improvements and practical expedients. The Partnership is currently evaluating the adoption of these standards and their impact on its 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 reviewed its VIEs and VOEs in connection with the adoption of this standard and determined no change to its previous conclusions was 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. The Partnership is currently evaluating the method of adoption and impact this standard will have on its 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 2016-06 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 its 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 its 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, classification of awards as either equity or liability, 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

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permitted. The Partnership is currently evaluating the method of adoption and impact this standard will have on its consolidated financial statements and related disclosures.

2. Acquisitions

Emerald Transactions

On April 25, 2016 and April 27, 2016, American Midstream Emerald, LLC ("Emerald"), a wholly-owned subsidiary of the Partnership, entered into two purchase and sale agreements with Emerald Midstream, LLC, an affiliate of ArcLight Capital Partners, LLC ("ArcLight"), the majority owner of our General Partner, for the purchase of membership interests in certain midstream entities.

On April 25, 2016, Emerald entered into the first purchase and sale agreement for the purchase of membership interests in entities that own and operate natural gas pipeline systems and NGL pipelines in and around Louisiana, Alabama, Mississippi, and the Gulf of Mexico (the "Pipeline Purchase Agreement"). Pursuant to the Pipeline Purchase Agreement, Emerald acquired (i) 49.7% of the issued and outstanding membership interests of Destin Pipeline Company, L.L.C. ("Destin"), (ii) 16.7% of the issued and outstanding membership interests of Tri-States NGL Pipeline, L.L.C. ("Tri-States"), and (iii) 25.3% of the issued and outstanding membership interests of Wilprise Pipeline Company, L.L.C. ("Wilprise" and collectively with Destin and Tri-States, the "Companies"), in exchange for approximately $183.6 million (the "Pipeline Transaction").

The Destin pipeline is a FERC-regulated, 255-mile natural gas transportation system with total capacity of 1.2 Bcf/d. The system originates offshore in the Gulf of Mexico and includes connections with four producing platforms, and six producer-operated laterals, including the Partnership's non-operated indirect interest in the Delta House floating production system and related pipeline infrastructure ("Delta House"). The 120-mile offshore portion of the Destin system terminates at the Pascagoula processing plant, owned by Enterprise Products Partners, LP, is the single source of raw natural gas to the plant. The onshore portion of Destin is the sole delivery point for merchant-quality gas from the Pascagoula processing plant and extends 135 miles north in Mississippi. Destin currently serves as the primary transfer of gas flows from the Barnett and Haynesville shale plays to Florida markets through interconnections with major interstate pipelines. Contracted volumes on the Destin pipeline are based on life-of-field dedication, dedicated volumes over a given period, or interruptible volumes as capacity permits. The Tri-States pipeline is a FERC-regulated, 161-mile natural gas liquids ("NGL") pipeline and sole form of transport to Louisiana-based fractionators for NGLs produced at the Pascagoula plant served by Destin and other facilities. The Wilprise pipeline is a FERC-regulated, approximately 30-mile NGL pipeline that originates at the Kenner Junction and terminates in Sorrento, Louisiana, where volumes flow via pipeline to a Baton Rouge fractionator.

On April 27, 2016, Emerald entered into a second purchase and sale agreement for the purchase of 66.7% of the issued and outstanding membership interests of Okeanos Gas Gathering Company, LLC ("Okeanos"), in exchange for a cash purchase price of approximately $27.4 million (such Purchase and Sale Agreement, the "Okeanos Purchase Agreement," and such transaction, the "Okeanos Transaction," and together with the Pipeline Transaction, the "Emerald Transactions"). The Okeanos pipeline is a 100-mile natural gas gathering system located in the Gulf of Mexico with a total capacity of 1.0 Bcf/d. The Okeanos pipeline connects two platforms and one lateral, terminating at the Destin Main Pass 260 platform in the Mississippi Canyon region of the Gulf of Mexico. Contracted volumes on the Okeanos pipeline are based on life-of-field dedication.

The Partnership funded the aggregate purchase price for the Emerald Transactions with the issuance of 8,571,429 shares of newly-designated Series C convertible preferred units (the “Series C Units”) representing limited partnership interests in the Partnership and a warrant (the “Warrant”) to purchase up to 800,000 common units representing limited partnership interests in the Partnership ("common units") at an exercise price of $7.25 per common unit amounting to a combined value of approximately $120.0 million, plus additional borrowings of $91.0 million under our Credit Agreement (as defined herein). Affiliates of our General Partner hold and participate in distributions on our Series C Units with such distributions being made in paid-in-kind Series C Units, cash or a combination thereof at the election of the Board of Directors of our General Partner.

Because our interests in the entities underlying the Emerald Transactions were previously owned by an affiliate of our General Partner, we accounted for our investments at our affiliate's carry-over basis of $212.0 million, which is recorded in Investment in unconsolidated affiliates in our condensed consolidated balance sheets, and as an investing activity of $100.9 million within the condensed consolidated statements of cash flows. The amount by which the carry-over basis exceeded total consideration was $1.0 million and is recorded as a contribution from our General Partner within the condensed consolidated statements of changes in partners' capital and noncontrolling interests. Pursuant to the individual limited liability company or operating agreements for the entities acquired in the Emerald Transactions, we have no management control or authority over the day-to-day operations over the assets acquired in the Emerald Transactions. Our interests acquired in the entities underlying the Emerald Transactions are accounted for as investments in unconsolidated affiliates in the condensed consolidated financial statements.

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For the three-months ended June 30, 2016, the Partnership recorded $4.2 million in earnings and received cash distributions of $5.4 million from the entities underlying the Emerald Transactions. The excess of the cash distributions received over the earnings recorded is classified as proceeds from Investment in unconsolidated affiliates, return of capital within cash flows from investing activities in our condensed consolidated statement of cash flows.

Gulf of Mexico Pipelines

On April 15, 2016, American Panther, LLC ("American Panther"), a 60%-owned subsidiary of the Partnership, acquired approximately 200 miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines ("Gulf of Mexico Pipeline") for approximately $3.1 million in cash and the assumption of certain asset retirement obligations. The Partnership exerts control over American Panther and therefore consolidates its financial activity for financial reporting purposes.

The acquisition was accounted for using the acquisition method of accounting and as a result, the aggregate purchase price was allocated to the assets acquired and liabilities assumed based on their respective fair values as of the acquisition date.

The following tables summarize the fair value of consideration transferred by the Partnership for the acquisition and the preliminary allocation of that amount to the assets acquired and liabilities assumed based on their respective fair values as of the acquisition date (in thousands).

Fair value of consideration transferred:	
Cash	$3,073

Fair value of assets acquired, liabilities assumed:	
Assets:	
Property, plant and equipment:	
Pipelines	$16,952
Land	421
Total property, plant and equipment	17,373
Liabilities:	
Asset retirement obligations	(14,300)
Fair value of net assets acquired and liabilities assumed	$3,073

American Panther contributed revenue of $4.3 million and net income of $2.6 million for the period of April 15, 2016 through June 30, 2016, which is included in the Partnership's Gathering and Processing segment. Additionally, the Partnership incurred $0.2 million of transaction costs related to the acquisition which are included in Selling, general and administrative expenses in our condensed consolidated statement of operations for the three months ended June 30, 2016.

Pro forma financial results are not presented as it is impractical to obtain the necessary information. The seller did not operate the acquired assets as a standalone business and, therefore, historical financial information is not available.

Additional Delta House Investment

On April 25, 2016, American Midstream Delta House, LLC ("AMID Delta House"), a wholly-owned subsidiary of the Partnership, entered into a unit purchase agreement with an affiliate of ArcLight, pursuant to which AMID Delta House acquired 100% of the outstanding membership interests in D-Day Offshore Holdings, LLC ("D-Day"), which owned (i) 912.4 Class A Units of Delta House FPS LLC and (ii) 53.5 Class A Units of Delta House Oil and Gas Lateral LLC in exchange for a cash purchase price of approximately $9.9 million funded with additional borrowings under the Partnership’s Credit Agreement. Delta House is a floating production system platform with associated crude oil and natural gas export pipelines, located in the Mississippi Canyon region of the deepwater Gulf of Mexico.

Because our interest in D-Day was previously owned by an affiliate of our General Partner, we have accounted for our investment at our affiliate's carry-over basis of $9.9 million, which is recorded in Investments in unconsolidated affiliates in our condensed consolidated balance sheets and as an investing activity within the condensed consolidated statements of cash flows.

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For the three-months ended June 30, 2016, the Partnership recorded $0.4 million in earnings and received cash distributions of $1.1 million from its D-Day investment. The excess of the cash distributions received over the earnings recorded is classified as a return of capital within cash flows from investing activities in our condensed consolidated statements of cash flows.

The investment in D-Day, together with our 26.3% interest in Pinto Offshore Holdings, LLC, an entity that owns a 49.0% non-operated interest in Delta House, results in the Partnership holding a combined 13.9% non-operated indirect interest in Delta House. Pursuant to the agreements governing the underlying entities, we have no management control or authority over the day-to-day operations of Delta House. Our interests in Delta House are accounted for as investments in unconsolidated affiliates in the condensed consolidated financial statements.

Divestitures

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

3. 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. 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 and six months ended June 30, 2016 and 2015, no allowances on or significant write-offs of accounts receivable were recorded.

During the three and six months ended June 30, 2016, one customer accounted for 10% and 11%, respectively, of the Partnership's consolidated revenue. During the three and six months ended June 30, 2015, no individual customer accounted for 10% or more of the Partnership's consolidated revenue.

4. Other Current Assets

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

	June 30, 2016	December 31, 2015
Prepaid insurance	$3,073	$ 3,948
Accrued distributions from unconsolidated affiliates	4,359	—
Other prepaid amounts	2,108	2,866
Other current assets	3,808	3,280
	$13,348	$ 10,094

5. 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. The 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 June 30, 2016, the aggregate notional volume of our commodity derivatives was 5.6 million gallons of NGLs, natural gasoline and crude oil equivalent for 2016 production.

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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 June 30, 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 Swaps

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. As of June 30, 2016, the total notional amount of our interest rate swaps was $300.0 million.

In the first quarter of 2016, we entered into interest rate swaps with a notional amount of $200.0 million. The interest rate swaps were entered into with a single counterparty and we were not required to post collateral. The interest rate swaps will expire September 3, 2019.

In the second quarter of 2016, we entered into additional interest rate swaps with a notional amount of $100.0 million. The interest rate swaps were entered into with a single counterparty and we were not required to post collateral. The interest rate swaps are effective beginning January 1, 2018 and will expire December 31, 2021.

Weather Derivative

In the second quarter of 2016, we entered into a weather derivative to mitigate the impact of potential unfavorable weather on our operations under which we could receive payments totaling up to $30.0 million in the event that a hurricane or hurricanes of certain strength pass through the areas identified in the derivative agreement. The weather derivative is accounted for using the intrinsic value method. The weather derivative was entered into with a single counterparty and we were not required to post collateral.

We paid premiums of $1.0 million and $0.9 million during the six months ended June 30, 2016 and 2015, respectively, which were 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 $0.9 million as of June 30, 2016. As of June 30, 2016 and December 31, 2015, the value associated with our commodity derivatives, interest rate swaps, and weather derivative were recorded in our condensed consolidated balance sheets as follows (in thousands):

Balance Sheet Classification	Gross Risk Management Assets		Gross Risk Management (Liabilities)		Net Risk Management Assets (Liabilities)	
	June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
Current	$ 944	$ 365	$ —	$ —	$ 944	$ 365
Noncurrent	—	—	—	—	—	—
Total assets	$ 944	$ 365	$ —	$ —	$ 944	$ 365
Current	$ —	$ —	$ (832)	$ —	$ (832)	$ —
Noncurrent	—	—	(2,556)	—	(2,556)	—
Total liabilities	$ —	$ —	$ (3,388)	$ —	$ (3,388)	$ —

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For the three and six months ended June 30, 2016 and 2015, respectively, the realized and unrealized gains (losses) associated with our commodity derivatives, interest rate swaps and weather derivative were recorded in our condensed consolidated statements of operations as follows (in thousands):

	Three months ended June 30, Gain (loss) on Derivatives		Six months ended June 30, Gain (loss) on derivatives	
Statement of Operations Classification	Realized	Unrealized	Realized	Unrealized
2016				
Gain (loss) on commodity derivatives, net	$(244)	$(522)	$(244)	$(625)
Interest expense	—	(2,033)	—	(2,763)
Direct operating expenses	(232)	—	(450)	—
Total	$(476)	$(2,555)	$(694)	$(3,388)
2015				
Gain (loss) on commodity derivatives, net	$252	$59	$391	$67
Interest expense	(101)	98	(203)	146
Direct operating expenses	(234)	—	(475)	—
Total	$(83)	$157	$(287)	$213

6. 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 Agreement 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 Agreement.

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 six months ended June 30, 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 swaps, included as part of Risk management assets and Risk management liabilities within our condensed consolidated balance sheets, that were measured at fair value on a recurring basis as of June 30, 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:					
June 30, 2016	$(625)	$—	$(625)	$ —	$(625)
December 31, 2015	—	—	—	—	—
Interest rate swaps:					
June 30, 2016	$(2,763)	$—	$(2,763)	$ —	$(2,763)
December 31, 2015	—	—	—	—	—

The unamortized portion of the premium paid to enter the weather derivative described in Note 5 "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.

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7. Property, Plant and Equipment, Net

Property, plant and equipment, net, as of June 30, 2016 and December 31, 2015 were as follows (in thousands):

	Useful Life (in years)	June 30, 2016	December 31, 2015
Land	N/A	$5,703	$ 5,282
Construction in progress	N/A	61,203	46,045
Buildings and improvements	4 to 40	9,959	9,864
Processing and treating plants	8 to 40	102,003	97,784
Pipelines and compressors	3 to 40	573,084	554,400
Storage	20 to 40	58,226	58,394
Equipment	5 to 20	37,065	22,207
Total property, plant and equipment		847,243	793,976
Accumulated depreciation		(164,134)	(145,963)
Property, plant and equipment, net		$683,109	$ 648,013

Of the gross property, plant and equipment balances at June 30, 2016 and December 31, 2015, $132.0 million and $111.9 million, respectively, were related to AlaTenn, American Midstream Midla, LLC ("Midla") and High Point Gathering Systems, our FERC regulated interstate and intrastate assets.

Capitalized interest was $0.5 million for the three months ended June 30, 2016 and 2015, respectively, and $1.0 million and $0.7 million for the six months ended June 30, 2016 and 2015, respectively.

Depreciation expense was $9.4 million and $7.6 million for the three months ended June 30, 2016 and 2015, respectively, and $18.2 million and $15.5 million for the six months ended June 30, 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 escrow were returned to the Partnership and canceled, while the Partnership agreed to pay the Costar sellers an additional $0.7 million in cash. The net impact of this settlement was recorded as a reduction in Property, plant and equipment, net and Limited partner interests in the first half of 2016.

8. Goodwill and Intangible Assets, Net

The carrying value of goodwill as of June 30, 2016 and December 31, 2015, all of which related to our Terminals segment, was $16.3 million.

The goodwill was contributed to the Partnership as part of the acquisition of Blackwater Midstream Holdings LLC ("Blackwater") and other related subsidiaries from an affiliate of our General Partner (the "Blackwater Acquisition").

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Intangible assets, net, consists of customer relationships and dedicated acreage agreements identified as part of the Costar and Lavaca 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):

	June 30, 2016	December 31, 2015
Gross carrying amount:		
Customer relationships	$53,400	$53,400
Dedicated acreage	53,350	53,350
	$106,750	$106,750
Accumulated amortization:		
Customer relationships	$(4,410)	$(3,124)
Dedicated acreage	(3,550)	(2,661)
	$(7,960)	$(5,785)
Net carrying amount:		
Customer relationships	$48,990	$50,276
Dedicated acreage	49,800	50,689
	$98,790	$100,965

Amortization expense on our intangible assets totaled $1.1 million and $1.5 million for the three months ended June 30, 2016 and 2015, respectively, and $2.2 million and $3.1 million for the six months ended June 30, 2016 and 2015, respectively.

9. Investment in unconsolidated affiliates

The following table summarizes our percentage ownership interests in investments in unconsolidated affiliates:

	Percentage Ownership
Destin	49.7 %
Tri-States	16.7 %
Delta House	13.9 %
Wilprise	25.3 %
Okeanos	66.7 %
Main Pass Oil Gathering Company, LLC ("MPOG")	66.7 %
Mesquite	47.3 %

The following table presents the activity in the Partnership's equity investments for the six months ended June 30, 2016 (in thousands):

	Destin	Tri-States	Delta House	Others (1)	Total
Balances at December 31, 2015	$—	$—	$56,525	$25,776	$82,301
Investments	122,830	56,681	9,873	32,515	221,899
Earnings in unconsolidated affiliates	2,027	869	14,264	1,830	18,990
Contributions	—	—	—	12,459	12,459
Distributions	(6,631)	(1,092)	(28,359)	(3,995)	(40,077)
Balances at June 30, 2016	$118,226	$56,458	$52,303	$68,585	$295,572

(1) Includes activity associated with our non-operated interests in Wilprise, Okeanos, MPOG and Mesquite.

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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:	June 30, 2016	December 31, 2015
Current assets	$170,283	$ 2,086
Non-current assets	1,470,286	288,617
Current liabilities	182,895	366
Non-current liabilities	475,602	23,617

	Three months ended June 30,		Six months ended June 30,	
Income Statements:	2016	2015	2016	2015
Total revenue	$87,054	$1,974	$151,997	$4,410
Operating expense	6,649	768	7,541	1,738
Net income	65,613	(2)	120,777	241

The unconsolidated affiliates described above were each determined to be variable interest entities 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 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 entity is limited to its equity investment as presented on the condensed consolidated balance sheet at June 30, 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.

10. Accrued Expenses and Other Current Liabilities

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

	June 30, 2016	December 31, 2015
Current portion of asset retirement obligation (a)	$6,826	$ 6,822
Accrued capital expenditures	8,299	3,984
Accrued expenses	11,788	3,178
Due to related parties	2,424	3,894
Other	7,740	7,157
	$37,077	$ 25,035

(a) Associated with certain Gathering and Processing assets.

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11. Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO.

Certain assets related to our Transmission segment have regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These asset retirement obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transmission services will cease, and we do not believe that such demand will cease for the foreseeable future. A portion of our regulatory obligations is related to assets that we plan to take out of service.

The following table is a reconciliation of the asset retirement obligations for the six months ended June 30, 2016 (in thousands):

Beginning asset retirement obligation	$35,371
Liabilities assumed	14,300
Expenditures	(11)
Accretion expense	596
Total ending asset retirement obligation	$50,256
Less: current portion	6,826
Long-term asset retirement obligation	$43,430

As a result of the Gulf of Mexico Pipeline acquisition, we have recorded an additional ARO of $14.3 million.

We are required to establish security against any potential secondary obligations relating to the abandonment of certain transmission assets that may be imposed on the previous owner by applicable regulatory authorities. As such, we have a restricted cash account maintained by a third party that amounted to $5.0 million as of June 30, 2016 and is presented in Other assets, net in our consolidated balance sheets.

12. Debt Obligations

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

	June 30, 2016	December 31, 2015
Revolving credit facility	$672,400	$ 525,100
Other debt	731	2,338
Total debt	673,131	527,438
Less: current portion	731	2,338
Long-term debt	$672,400	$ 525,100

Effective as of April 25, 2016, the Partnership entered into the Second Amendment to the Amended and Restated Credit Agreement, (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 a consolidated total leverage ratio which requires our indebtedness not to 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 may be increased to 5.25 times adjusted consolidated EBITDA) and a minimum interest coverage ratio 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 events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). As of June 30, 2016, our consolidated total leverage ratio was 4.15 and our interest coverage ratio was 8.86, which was in compliance with the related requirements.

For the six months ended June 30, 2016 and 2015, the weighted average interest rate on borrowings under our Credit Agreement was approximately 4.35% and 3.15%, respectively.

At June 30, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $5.4 million and $1.8 million, respectively.

As of June 30, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the consolidated total 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.

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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13. 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 June 30, 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, including 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 and newly issued Series C Units (see below for further details) with such distributions being made in paid-in-kind units, cash or a combination thereof, at the election of the Board of Directors of our General Partner. The Series A Units and Series C Units are entitled to vote along with Limited Partner common unitholders and such units are currently convertible to common units.

On February 1, 2016, all outstanding Series B Units were converted on a one-for-one basis into common units. Prior to their conversion, 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. The holders of Series B Units were entitled to vote along with the holders of common units prior to conversion.

At-The-Market ("ATM") Offering

On October 18, 2015, we filed a prospectus supplement related to the offer and sale from time to time of common units in an at-the-market offering. For the six months ended June 30, 2016, we sold 248,561 common units for proceeds of $3.2 million, net of commissions and accrued offering costs of less than $0.1 million, which were used for general partnership purposes including the repayment of amounts outstanding under the Credit Agreement, the funding of acquisitions and the funding of capital expenditures. As of June 30, 2016, approximately $96.8 million remained available for sale under the Partnership's ATM Equity Offering Sales Agreement.

Series C Convertible Preferred Units

On April 25, 2016, the Series C Convertible Preferred Units (the "Series C Units") were created and issued pursuant to the Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP ("Partnership Agreement").

The Series C Units have the right to receive cumulative distributions in the same priority as the Series A Units, which is before any other distributions made in respect of any other partnership interests, in the amounts described herein with such distributions being made in paid-in-kind units, cash or a combination thereof, at the election of the Board of Directors of our General Partner. If all or any portion of a distribution on the Series C Units is to be paid in cash, then the aggregate amount of such cash to be distributed in respect of the Series C Units outstanding will be paid out of available cash in the same priority as any cash distributions made to the Series A unitholders, which will be made prior to any distributions to the General Partner or our common unitholders. To the extent that any portion of a distribution on Series C units (or Series A units) to be paid in cash exceeds the amount of Available Cash (as defined in the Partnership Agreement), an amount of cash equal to the Available Cash will be paid pro rata to the Series A unitholders and the Series C unitholders and the balance of such Series A quarterly distribution and Series C quarterly distributions will become an arrearage until paid in a future quarter.

The Series C Units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class on an as converted basis, with each Series C Unit initially entitled to one vote for each common unit into which such Series C Unit is convertible. The Series C Units also have separate class voting rights on any matter, including a merger, consolidation or business combination, that adversely affects, amends or modifies any of the rights, preferences, privileges or terms of the Series C Units. The Series C Units are convertible in whole or in part into common units at any time. The number of common units into which a Series C Unit is convertible will be an amount equal to (i) the sum of $14.00 and all accrued and accumulated but unpaid distributions, divided by (ii) the conversion price.

In the event that the Partnership issues, sells or grants any common units or convertible securities at an indicative per common unit price that is less than $14.00 per common unit (subject to customary anti-dilution adjustments), then the conversion will be adjusted according to a formula to provide for an increase in the number of common units into which Series C Units are convertible.

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Upon any liquidation and winding up of the Partnership or the sale of substantially all of the assets of the Partnership, the holders of Series C Units generally will be entitled to receive, in preference to the holders of any of the Partnership's other securities, an amount equal to the sum of the $14.00 multiplied by the number of Series C Units owned by such holders, plus all accrued but unpaid distributions.

Call Right

At any time prior to April 25, 2017, the Partnership has the right (the "Series C Call Right") to require the holders of the Series C Units to sell, assign and transfer all or a portion of the then outstanding Series C Units to the Partnership for a purchase price of $14.00 per Series C Unit (subject to customary anti-dilution adjustments), plus all accrued but unpaid distributions on each Series C Unit.

The Partnership may not exercise the Series C Call Right with respect to any Series C Unit if the holder has elected to convert it into common units on or prior to the date the Partnership has provided notice of its intent to exercise its Series C Call Right, and may not exercise the Series C Call Right if doing so would violate applicable law or result in a default under any financing agreement or obligation of the Partnership or its affiliates.

Warrant

On April 25, 2016, pursuant to the Securities Purchase Agreement, the Partnership issued the Warrant to Magnolia Infrastructure Partners, LLC ("Magnolia," an affiliate of our General Partner), which allows it to purchase up to 800,000 common units at an exercise price of $7.25 per common unit. The Warrant is subject to standard anti-dilution adjustments and is exercisable for a period of seven years.

On April 25, 2017, the number of common units that may be purchased pursuant to the exercise of the Warrant will be adjusted by an amount, rounded to the nearest whole common unit, equal to the product obtained by the following calculation: (i) 400,000 multiplied by (ii) (A) the Series C Issue Price multiplied by the number of Series C Units then outstanding less $45.0 million divided by (B) the Series C Issue Price multiplied by the number of Series C Units issued, less $45.0 million.

Each issuance of any Series C Units issued in-kind as a distribution to holders of Series C Units ("Series C PIK Units") will increase the number of common units that can be purchased upon exercise of the Warrant by an amount, rounded to the nearest whole common unit, equal to the product obtained by the following calculation: (i) the total number of common units into which each Warrant may be exercised immediately prior to the most recent issuance of the Series C PIK Units multiplied by (ii) (A) the total number of outstanding Series C Units immediately after the most recent issuance of Series C PIK Units divided by (B) the total number of outstanding Series C Units immediately prior to the most recent issuance of Series C PIK Units.

The fair value of the Warrant was determined using a market approach that utilized significant inputs which are not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. The estimated fair value of $4.41 per warrant unit was determined using a Black-Scholes model and the following significant assumptions: i) a dividend yield of 18%, ii) common unit volatility of 42% and iii) the seven-year term of the warrant to arrive at an aggregate fair value of $4.5 million.

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $1.8 million from our General Partner as consideration for the issuance of 128,272 additional notional general partner units for the six months ended June 30,

2016. For the six months ended June 30, 2015, we received proceeds of $0.3 million for the issuance of 18,706 additional notional general partner units.

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Outstanding Units

The number of units outstanding as of June 30, 2016 and December 31, 2015, respectively, were as follows (in thousands):

	June 30, 2016	December 31, 2015
Series A convertible preferred units	9,797	9,210
Series B convertible units	—	1,350
Series C convertible preferred units	8,571	—
Limited Partner common units	31,146	30,427
General Partner units	664	536

Distributions

We made cash distributions as follows (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Limited Partner common units	$12,745	$10,753	$27,763	$21,466
General Partner units	173	159	395	317
General Partners' incentive distribution rights	—	1,293	1,806	2,581
	$12,918	$12,205	$29,964	$24,364

On July 21, 2016, the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per unit for the quarter ended June 30, 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 is expected to be paid on August 12, 2016, to unitholders of record as of the close of business on August 3, 2016. At June 30, 2016, we had accrued contractual cash distributions of $2.4 million and $2.2 million of paid-in-kind Series A Units that will be issued in August 2016. At June 30, 2016, we accrued contractual cash distributions of $1.3 million and $0.9 million of paid-in-kind Series C Units that will be issued in August 2016.

For the six months ended June 30, 2016, the Partnership issued 586,882 of paid-in-kind Series A Units and accrued a combination of cash and paid-in-kind unitholder distributions for Series A Units with a fair value of $9.1 million. For the six months ended June 30, 2015, the Partnership issued 365,641 of paid-in-kind Series A Units and accrued a combination of cash and paid-in-kind unitholder distributions for Series A Units with a fair value of $7.6 million.

The fair value of the paid-in-kind Series A and C Unit distributions for all quarters presented was determined primarily using the market and income approaches, requiring 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, and iii) assumed discount rates of 10.0% and 18.0%, respectively.

Net Income (Loss) attributable to Limited Partners

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 and Series C Units, declared distributions on the Series B Units, 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 limited partners' net income (loss) per common unit. Basic and diluted limited partners' net income (loss) per common 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 limited partners' net income (loss) per common unit as follows (in thousands, except per unit amounts):

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	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Net income (loss) from continuing operations	$(3,591)	$(2,002)	$(7,555)	$(1,166)
Less: Net income (loss) attributable to noncontrolling interests	992	32	979	46
Net income (loss) from continuing operations attributable to the Partnership	(4,583)	(2,034)	(8,534)	(1,212)
Less:				
Distributions on Series A Units	4,602	4,196	9,073	7,607
Distributions on Series C Units	2,249	—	2,249	—
Declared distributions on Series B Units	—	413	—	833
General partner's distribution	173	1,452	2,201	2,899
General partner's share in undistributed loss	(322)	(234)	(659)	(422)
Net income (loss) from continuing operations available to Limited Partners	(11,285)	(7,861)	(21,398)	(12,129)
Net income (loss) from discontinued operations available to Limited Partners	—	(31)	—	(26)
Net income (loss) available to Limited Partners	$(11,285)	$(7,892)	$(21,398)	$(12,155)
Weighted average number of common units used in computation of Limited Partners' net income (loss) per common unit (basic and diluted)	30,949	22,757	30,884	22,730
Limited Partners' net income (loss) per common unit (basic and diluted)	$(0.36)	$(0.35)	$(0.69)	$(0.53)

14. 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 to 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") which, among other things, increased the number of available awards by 6,000,000 common units. At June 30, 2016 and December 31, 2015, there were 4,941,325 and 15,484 common unit, respectively, available for future issuance under the LTIP.

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 common 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 DERs based on the extent to which the Partnership's Series A 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.

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The following table summarizes activity in our phantom unit-based awards for the six months ended June 30, 2016:

	Units	Weighted-Average Grant Price
Outstanding at beginning of period	569,759	$ 13.15
Granted	1,177,509	1.05
Forfeited	(102,934)	5.36
Vested	(179,326)	11.75
Outstanding at end of period	1,465,008	$ 4.14

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our common units at the grant date. Compensation costs related to these awards, including amortization applicable to prior awards, for the three months ended June 30, 2016 and 2015 were $1.0 million and $0.6 million, respectively, and for the six months ended June 30, 2016 and 2015, were $2.1 million and $2.2 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 $1.0 million and $2.3 million for the six months ended June 30, 2016 and 2015, respectively.

Equity compensation expense related to unvested awards not yet recognized at June 30, 2016 and 2015 was $5.0 million and $6.0 million, respectively, and the weighted average period over which this cost is expected to be recognized as of June 30, 2016 was approximately 2.4 years.

Performance and Service Condition Awards. In November 2015, the Board of Directors of our General Partner modified awards to introduce certain performance and service conditions that we believe are probable of being achieved, amounting to $2.0 million payable in a variable amount of phantom units awards at the time of grant. 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 and six months ended June 30, 2016 was $0.4 million and $0.6 million, respectively. Compensation costs related to unvested awards not yet recognized at June 30, 2016 was $0.9 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:

	Six months ended June 30, 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 and six months ended June 30, 2016 was immaterial. Compensation costs related to unvested awards not yet recognized at June 30, 2016 was $0.1 million.

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15. 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 and six months ended June 30, 2016 was $0.5 million and $0.9 million, respectively, resulting in an effective tax rate of 17.7% and 12.8%, respectively. For the three and six months ended June 30, 2015, income tax expense was $0.3 million and $0.5 million, respectively, resulting in an effective tax rate of 18.8% and 68.3%, respectively.

The effective tax rates for the three and six months ended June 30, 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 and state 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 consolidation.

16. Commitments and Contingencies

Legal proceedings

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

Environmental matters

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

Regulatory matters

On October 8, 2014, 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 commenced in the second quarter of 2016 with service expected to begin in early 2017. 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

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 until their respective termination date. Charges associated with one-time termination benefits will be recognized ratably over the requisite service period and presented in Selling, general and administrative expenses. We have estimated the fair value of the initial charge to be approximately $3.6 million, of which $2.5 million has been recorded in Accrued expenses and other current liabilities as of June 30, 2016. We expect the plan to be complete by the fourth quarter of 2016.

As part of the corporate relocation plan we have executed a 16-year office sublease as of June 29, 2016 with an estimated operating lease commitment of approximately $15.9 million.

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17. 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 and six months ended June 30, 2016, administrative payroll and operational services expenses of $8.9 million and $16.9 million, respectively, were charged to the Partnership by our General Partner. During the three and six months ended June 30, 2015, administrative payroll and operational services expenses of $6.9 million and $14.2 million, respectively, were charged to the Partnership by our General Partner.

For the three and six months ended June 30, 2016, our General Partner incurred approximately $0.1 million and $0.4 million, respectively, of business development expenses that were funded by the Partnership. For the three and six months ended June 30, 2015, our General Partner incurred approximately $0.5 million and $0.9 million of such costs. If the business development activities result in a project that will be pursued and funded by the Partnership, we will reimburse our General Partner for the related costs and record those costs in our consolidated statements of operations.

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 and six months ended June 30, 2016, the Partnership recognized $0.2 million and $0.4 million, respectively, in management fee income, and recognized $0.4 million and $0.9 million, respectively, for the three and six months ended June 30, 2015 that was recorded as a reduction to Selling, general and administrative expenses. For the three and six months ended June 30, 2016, an affiliate of our General Partner also incurred approximately $0.3 million and $0.2 million, respectively, of costs associated with reimbursable costs incurred on behalf of these affiliates. For the three and six months ended June 30, 2015, an affiliate of our General Partner also incurred approximately $0.5 million and $0.9 million, respectively, of costs associated with reimbursable costs incurred on behalf of these affiliates.

As of June 30, 2016 and December 31, 2015, the Partnership had $2.4 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 related to the foregoing transactions.

18. 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 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, including local distribution companies ("LDCs"), utilities and industrial, commercial and power generation customers.

Terminals

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

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

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The following tables set forth our segment information for the three and six months ended June 30, 2016 and 2015 (in thousands):

	Three months ended June 30, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$41,780	$ 8,740	$ 5,628	$56,148
Gain (loss) on commodity derivatives, net	(764)	(2)	—	(766)
Total revenue	41,016	8,738	5,628	55,382
Operating expenses:				
Purchases of natural gas, NGL's and condensate	20,964	1,138	—	22,102
Direct operating expenses	11,231	3,425	1,535	16,191
Selling, general and administrative expenses				11,432
Equity compensation expense				1,025
Depreciation, amortization and accretion expense				10,903
Total operating expenses				61,653
Gain (loss) on sale of assets, net				80
Interest expense				(8,507)
Earnings in unconsolidated affiliates				11,647
Income tax (expense) benefit				(540)
Net income (loss)				(3,591)
Less: Net income (loss) attributable to noncontrolling interests				992
Net income (loss) attributable to the Partnership				$(4,583)
Segment gross margin (a)	$20,605	$ 7,593	$ 4,093	$32,291

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue plus unrealized losses on commodity derivatives of $0.5 million and loss on construction and operating management agreement ("COMA") of less than $0.1 million, less purchases of natural gas, NGLs and condensate.

Segment gross margin for our Transmission segment consists of total revenue less COMA income of less than $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

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	Three months ended June 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$50,439	$ 12,423	$ 4,336	$67,198
Gain (loss) on commodity derivatives, net	311	—	—	311
Total revenue	50,750	12,423	4,336	67,509
Operating expenses:				
Purchases of natural gas, NGL's and condensate	30,272	3,062	—	33,334
Direct operating expenses	9,130	3,253	1,584	13,967
Selling, general and administrative expenses				5,571
Equity compensation expense				550
Depreciation, amortization and accretion expense				9,250
Total operating expenses				62,672
Gain (loss) on sale of assets, net				(2,970)
Interest expense				(3,556)
Earnings in unconsolidated affiliate				4
Income tax (expense) benefit				(317)
Income (loss) from discontinued operations, net of tax				(31)
Net income (loss)				(2,033)
Less: Net income (loss) attributable to noncontrolling interests				32
Net income (loss) attributable to the Partnership				$(2,065)
Segment gross margin (a)	$20,219	$ 9,333	$ 2,752	$32,304

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized gains on commodity derivatives of $0.1 million, (ii) COMA income of $0.2 million and (iii) purchases of natural gas, NGLs and condensate.

(b) Segment gross margin for our Transmission segment consists of total revenue less COMA income of less than $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

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	Six months ended June 30, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$72,928	$ 18,967	$ 10,376	$102,271
Gain (loss) on commodity derivatives, net	(867)	(2)	—	(869)
Total revenue	72,061	18,965	10,376	101,402
Operating expenses:				
Purchases of natural gas, NGL's and condensate	36,412	2,602	—	39,014
Direct operating expenses	21,234	6,266	3,212	30,712
Selling, general and administrative expenses				19,966
Equity compensation expense				2,109
Depreciation, amortization and accretion expense				20,997
Total operating expenses				112,798
Gain (loss) on sale of assets, net				90
Interest expense				(14,379)
Earnings in unconsolidated affiliates				18,990
Income tax (expense) benefit				(860)
Net income (loss)				(7,555)
Less: Net income (loss) attributable to noncontrolling interests				979
Net income (loss) attributable to the Partnership				$(8,534)
Segment gross margin (a)	$36,336	$ 16,348	$ 7,164	$59,848

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue plus unrealized losses on commodity derivatives of $0.6 million and loss on COMA of $0.1 million, less purchases of natural gas, NGLs and condensate.

(b) Segment gross margin for our Transmission segment consists of total revenue less COMA income of less than $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

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	Six months ended June 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$98,888	$ 24,171	$ 8,601	$131,660
Gain (loss) on commodity derivatives, net	458	—	—	458
Total revenue	99,346	24,171	8,601	132,118
Operating expenses:				
Purchases of natural gas, NGL's and condensate	57,590	4,721	—	62,311
Direct operating expenses	18,223	6,432	3,179	27,834
Selling, general and administrative expenses				12,506
Equity compensation expense				2,248
Depreciation, amortization and accretion expense				18,939
Total operating expenses				123,838
Gain (loss) on sale of assets, net				(2,978)
Interest expense				(6,166)
Earnings in unconsolidated affiliates				171
Income tax (expense) benefit				(473)
Income (loss) from discontinued operations, net of tax				(26)
Net income (loss)				(1,192)
Less: Net income (loss) attributable to noncontrolling interests				46
Net income (loss) attributable to the Partnership				$(1,238)
Segment gross margin (a)	$41,265	$ 19,394	$ 5,422	$66,081

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized gains on commodity derivatives of $0.1 million, (ii) COMA income of $0.4 million and (iii) purchases of natural gas, NGLs and condensate.

Segment gross margin for our Transmission segment consists of total revenue less COMA income of $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

A reconciliation of total assets by segment to the amounts included in the condensed consolidated balance sheets follows:

	June 30, 2016	December 31, 2015
Segment assets:		
Gathering and Processing	$586,782	$572,824
Transmission	151,518	133,870
Terminals	94,790	84,449
Other (a)	317,878	100,153
Total assets	$1,150,968	$891,296

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

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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 ("Quarterly Report") and the audited consolidated financial statements and notes thereto and management’s discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 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 About 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 Agreement (as defined herein);
- 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

- 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 13 gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines, three marine terminal sites and one crude oil pipeline. 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 2.2 million barrels of storage capacity across three marine terminal sites.

Financial highlights for the three months ended June 30, 2016, include the following:

- Net income (loss) attributable to the Partnership decreased to $4.6 million, primarily due to higher total operating expenses and an increase in interest expense as a result of unfavorable unrealized losses on interest rate swaps and additional borrowings to fund capital growth and acquisitions, partially offset by an increase in earnings from unconsolidated affiliates;

- The Partnership entered into various purchase and sale agreements for the purchase of membership interests in entities that own and operate natural gas pipeline systems and NGL pipelines in and around Louisiana, Alabama, Mississippi, and the Gulf of Mexico that contributed $4.2 million in earnings and from which the Partnership received cash distributions of $5.4 million;

- American Panther, LLC ("American Panther"), a 60%-owned subsidiary of the Partnership, acquired approximately 200 miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines that contributed revenue of $4.3 million and net income of $2.6 million for the period of April 15, 2016 through June 30, 2016;

- Gross margin amounted to $32.3 million consistent with the same period in 2015 primarily due to higher firm storage contracted capacity offset by lower average firm and interruptible transportation throughput volumes associated with our Transmission segment;

- Adjusted EBITDA increased to $36.1 million, or an increase of 149.0%, as compared to the same period in 2015 primarily due to distributions from our investments in Delta House and the entities underlying the Emerald

Transactions; and

- We distributed $12.7 million to our common unitholders, or $0.4125 per unit.

Operational highlights for the three months ended June 30, 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 88.2% as compared to 82.7% for the same period in 2015;

- Contracted capacity for our Terminals segment averaged 2,018,233 Bbls, representing a 39.3% increase compared to the same period in 2015;

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- Average condensate production totaled 100.2 Mgal/d, representing a 4.4 Mgal/d increase compared to the same period in 2015;
- Average gross NGL production totaled 217.3 Mgal/d, representing a 113.8 Mgal/d decrease compared to the same period in 2015; and
- Throughput volumes attributable to the Partnership totaled 1,019.7 MMcf/d, representing a 11.5 MMcf/d decrease 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 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.

Acquisition of interests in Gulf of Mexico midstream assets

In April 2016, we announced the acquisition of interests in Gulf of Mexico midstream assets and an incremental ownership interest in Delta House 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. We 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 our total indirect interest in Delta House 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, estimated to have a fair value of approximately $120.0 million, and additional borrowings under our Credit Agreement of approximately $105.0 million.

Commodity Prices

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $51.23 per barrel to a low of $26.21 per barrel from January 1, 2016 through August 2, 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $2.99 per MMBtu to a low of $1.64 per MMBtu from January 1, 2016 through August 2, 2016. During 2016, we entered into commodity contracts with existing counterparties and economically hedged approximately 43% of our expected exposure to NGL prices and 56% of our expected exposure to oil prices through the end of 2016.

Fluctuations in energy prices, like the recent depressed 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, which include a maximum total leverage ratio which is measured 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 June 30, 2016, our Gathering and Processing segment derived 10% of its revenue from each of ConocoPhilips Company and Eastman Chemical Company. For the three months ended June 30, 2016, our Transmission segment derived 23% and 16% of its revenue from Superior Natural Gas Corporation and ConocoPhilips Company, respectively, who were the two largest purchasers of natural gas and transmission capacity.

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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.

Distribution

On July 21, 2016, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit for the quarter ended June 30, 2016, or $1.65 per unit on an annualized basis. The distribution is expected to be paid on August 12, 2016, to unitholders of record as of the close of business on August 3, 2016.

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 upside in higher commodity-price environments is limited to an

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increase in throughput volumes from producers. 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

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 June 30, 2016 and 2015, $28.5 million and $26.7 million, or 88.2% and 82.7%, 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 June 30, 2016 and 2015 (in thousands):

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	For the Three Months Ended June 30, 2016			For the Three Months Ended June 30, 2015		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gathering and Processing						
Fee-based	$14,361	69.7	%	$9,260	45.8	%
Fixed margin	2,411	11.7	%	5,358	26.5	%
Percent-of-proceeds	3,833	18.6	%	5,601	27.7	%
Total	$20,605	100.0	%	$20,219	100.0	%
Transmission						
Firm transportation	$2,802	36.9	%	$2,884	30.9	%
Interruptible transportation	4,791	63.1	%	6,449	69.1	%
Total	$7,593	100.0	%	$9,333	100.0	%
Terminals						
Firm storage	$4,093	100.0	%	$2,752	100.0	%
Total	$4,093	100.0	%	$2,752	100.0	%

For the six months ended June 30, 2016 and 2015, $53.6 million and $55.5 million, or 89.6% and 84.0%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts. Set forth below is a table summarizing our average contract mix relative to segment gross margin for the six months ended June 30, 2016 and 2015 (in thousands):

	For the Six Months Ended June 30, 2016			For the Six Months Ended June 30, 2015		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gathering and Processing						
Fee-based	$25,181	69.3	%	$19,064	46.2	%
Fixed margin	4,942	13.6	%	11,637	28.2	%
Percent-of-proceeds	6,213	17.1	%	10,564	25.6	%
Total	$36,336	100.0	%	$41,265	100.0	%
Transmission						
Firm transportation	$6,621	40.5	%	$6,012	31.0	%
Interruptible transportation	9,727	59.5	%	13,382	69.0	%
Total	$16,348	100.0	%	$19,394	100.0	%
Terminals						
Firm storage	$7,164	100.0	%	$5,422	100.0	%
Total	$7,164	100.0	%	$5,422	100.0	%

Cash distributions derived from our unconsolidated affiliates amounted to $26.6 million and $0.5 million for the three months ended June 30, 2016 and 2015, respectively, and $40.1 million and $1.5 million for the six months ended June 30, 2016 and 2015, respectively. Cash distributions derived from our unconsolidated affiliates 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

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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 total revenue generated from gathering and processing operations less unrealized gain or plus unrealized (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 total revenue generated from firm and interruptible transportation agreements and fixed-margin arrangements, plus other related fees, less COMA income and 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.

Operating Margin

Operating Margin is a metric that we use to evaluate our performance. We define operating margin as total gross margin less direct operating expenses. The GAAP measure most directly comparable to operating margin is net income (loss) attributable to the Partnership.

Direct Operating Expenses

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

Adjusted EBITDA

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

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash flow from operations to make cash distributions to our unitholders and our General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

We define Adjusted EBITDA as net income (loss) attributable to the Partnership, plus interest expense, income tax expense, depreciation, amortization and accretion expense attributable to the Partnership, certain non-cash charges such as non-cash equity compensation expense, unrealized (gains) losses on derivatives, debt issuance costs paid during the period, proceeds from investments in unconsolidated affiliates, return of capital, transaction expenses and selected charges that are unusual or nonrecurring, less COMA income, OPEB plan net periodic benefit, gains (losses) on the sale of assets, net, 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, operating margin and Adjusted EBITDA are performance measures that are non-GAAP financial measures. Each has important limitations as an analytical tool because they exclude 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, operating 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, segment gross margin, operating 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, operating margin and Adjusted EBITDA used by management to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for the three and six months ended June 30, 2016 and 2015 (in thousands):

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	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership:				
Gathering and Processing segment gross margin	$20,605	$20,219	$36,336	$41,265
Transmission segment gross margin	7,593	9,333	16,348	19,394
Terminals segment gross margin (a)	4,093	2,752	7,164	5,422
Total Gross Margin	32,291	32,304	59,848	66,081
Less:				
Direct operating expenses (a)	14,656	12,383	27,500	24,655
Total Operating Margin	17,635	19,921	32,348	41,426
Plus:				
Gain (loss) on commodity derivatives, net	(766)	311	(869)	458
Earnings in unconsolidated affiliates	11,647	4	18,990	171
Less:				
Selling, general and administrative expenses	11,432	5,571	19,966	12,506
Equity compensation expense	1,025	550	2,109	2,248
Depreciation, amortization and accretion expense	10,903	9,250	20,997	18,939
(Gain) loss on sale of assets, net	(80)	2,970	(90)	2,978
Interest expense	8,507	3,556	14,379	6,166
Other, net (b)	(220)	24	(197)	(89)
Income tax expense	540	317	860	473
(Income) loss from discontinued operations, net of tax	—	31	—	26
Net income (loss) attributable to noncontrolling interest	992	32	979	46
Net income (loss) attributable to the Partnership	$(4,583)	$(2,065)	$(8,534)	$(1,238)

(a) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $11.2 million and $9.1 million, respectively, and Transmission segment direct operating expenses of $3.4 million and $3.3 million, respectively, for the three months ended June 30, 2016 and 2015. Direct operating expenses related to our Terminals segment of $1.5 million and $1.6 million for the three months ended June 30, 2016 and 2015, respectively, are included within the calculation of Terminals segment gross margin.

Direct operating expenses includes Gathering and Processing segment direct operating expenses of $21.2 million and $18.2 million, respectively, and Transmission segment direct operating expenses of $6.3 million and $6.4 million, respectively, for the six months ended June 30, 2016 and 2015. Direct operating expenses related to our Terminals segment of $3.2 million and $3.2 million, respectively, for the six months ended June 30, 2016 and 2015 are included within the calculation of Terminals segment gross margin.

(b) Other, net includes realized gain (loss) on commodity derivatives of $(0.2) million and $0.3 million, respectively, and COMA income (loss) of less than $(0.1) million and $0.2 million, respectively, for the three months ended June 30, 2016 and 2015.

Other, net includes realized gain (loss) on commodity derivatives of $(0.2) million and $0.4 million, respectively, and COMA income (loss) of less than $(0.1) million and $0.5 million, respectively, for the six months ended June 30, 2016 and 2015, respectively.

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	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Reconciliation of Adjusted EBITDA to Net income (loss) attributable to the Partnership:				
Net income (loss) attributable to the Partnership	$(4,583)	$(2,065)	$(8,534)	$(1,238)
Add:				
Depreciation, amortization and accretion expense	10,690	9,250	20,784	18,939
Interest expense	5,937	3,360	10,629	5,744
Debt issuance costs	1,340	46	1,475	276
Unrealized (gain) loss on derivatives, net	2,555	(157)	3,388	(213)
Non-cash equity compensation expense	1,025	550	2,109	2,248
Transaction expenses	3,782	—	4,658	43
Income tax expense	540	297	860	457
Proceeds from investments in unconsolidated affiliates, return of capital	14,916	496	21,088	1,329
Deduct:				
COMA income	(23)	229	(47)	481
OPEB plan net periodic benefit	4	3	8	6
Gain (loss) on sale of assets, net	80	(2,970)	90	(2,978)
Adjusted EBITDA	$36,141	$14,515	$56,406	$30,076

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

Net loss attributable to the Partnership increased by $2.5 million for the three months ended June 30, 2016, and increased by $7.3 million, for the six months ended June 30, 2016 as compared to the same periods in 2015. For the three months ended June 30, 2016, direct operating expenses increased by $2.2 million due to certain integrity management programs and environmental regulations, selling, general and administrative expenses increased by $5.8 million largely due to incremental transaction costs and corporate relocation expenses which are a one-time charge, interest expense increased by $4.9 million as a result of unfavorable unrealized losses on interest rate swaps along with additional borrowings to fund capital growth and acquisitions and earnings from unconsolidated affiliates increased by $11.6 million. For the six months ended June 30, 2016, total gross margins decreased by $6.3 million due to reasons explained below, direct operating expenses increased by $2.9 million due to certain integrity management programs and environmental regulations, selling, general and administrative expenses increased by $7.5 million largely due to incremental transaction expenses, some of which are non-recurring, interest expense increased by $8.2 million as a result of additional borrowings to fund capital growth and acquisitions and earnings from unconsolidated affiliates increased by $18.8 million.

Gross margin remained consistent at $32.3 million for the three months ended June 30, 2016 and decreased by $6.3 million, or 9.5%, for the six months ended June 30, 2016 as compared to the same periods in 2015. For the three months ended June 30, 2016, gross margin was flat due to higher firm storage contracted capacity amounting to $1.3 million, which was offset by lower average firm and interruptible transportation throughput volumes associated with our Transmission segment amounting to $1.7 million. The lower gross margin associated with our Transmission segment was the result of a decrease in average throughput volumes of 9.2%. For the six months ended June 30, 2016, the decrease in gross margin was primarily a result of a decline in our Gathering and Processing segment gross margins of $5.0 million and a decline in our Transmission segment gross margins of $3.1 million due to lower throughput volumes and lower commodity prices offset by an increase in our Terminals segment gross margins of $1.8 million due to an increase in firm storage contracted capacity.

For the three months ended June 30, 2016, Adjusted EBITDA increased $21.6 million, or 149.0%, compared to the same period in 2015. The increase is primarily related to higher cash distributions derived from our unconsolidated affiliates of $26.1 million largely due to our investments in Delta House and the entities underlying the Emerald Transactions. For the six months ended

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June 30, 2016, Adjusted EBITDA increased $26.3 million, or 87.4%, compared to the same period in 2015. The increase is primarily related to higher cash distributions derived from our unconsolidated affiliates of $38.6 million largely due to our investments in Delta House and the entities underlying the Emerald Transactions, partially offset by an increase in interest expense of $4.9 million and an increase in transaction expenses of $4.6 million related to additional borrowings and charges associated with funding capital growth projects and acquisitions.

We distributed $12.7 million to holders of our common units, or $0.4125 per unit, during the three months ended June 30, 2016, and $27.8 million, or $0.8850 per unit, during the six months ended June 30, 2016.

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):

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Statement of Operations Data:				
Revenue	$56,148	$67,198	$102,271	$131,660
Gain (loss) on commodity derivatives, net	(766)	311	(869)	458
Total revenue	55,382	67,509	101,402	132,118
Operating expenses:				
Purchases of natural gas, NGLs and condensate	22,102	33,334	39,014	62,311
Direct operating expenses	16,191	13,967	30,712	27,834
Selling, general and administrative expenses	11,432	5,571	19,966	12,506
Equity compensation expense (a)	1,025	550	2,109	2,248
Depreciation, amortization and accretion expense	10,903	9,250	20,997	18,939
Total operating expenses	61,653	62,672	112,798	123,838
Gain (loss) on sale of assets, net	80	(2,970)	90	(2,978)
Operating income (loss)	(6,191)	1,867	(11,306)	5,302
Other income (expense):				
Interest expense	(8,507)	(3,556)	(14,379)	(6,166)
Earnings in unconsolidated affiliates	11,647	4	18,990	171
Net income (loss) before income tax (expense) benefit	(3,051)	(1,685)	(6,695)	(693)
Income tax (expense) benefit	(540)	(317)	(860)	(473)
Net income (loss) from continuing operations	(3,591)	(2,002)	(7,555)	(1,166)
Income (loss) from discontinued operations, net of tax	—	(31)	—	(26)
Net income (loss)	(3,591)	(2,033)	(7,555)	(1,192)
Net income (loss) attributable to noncontrolling interests	992	32	979	46
Net income (loss) attributable to the Partnership	$(4,583)	$(2,065)	$(8,534)	$(1,238)
Other Financial Data:				
Gross margin (b)	$32,291	$32,304	$59,848	$66,081
Adjusted EBITDA (b)	$36,141	$14,515	$56,406	$30,076

(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 June 30, 2016 Compared to Three Months Ended June 30, 2015

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Total Revenue. Our total revenue for the three months ended June 30, 2016 was $55.4 million compared to $67.5 million for the three months ended June 30, 2015. This decrease of $12.1 million was primarily due to the following:

- a decrease in NGL revenues of $6.1 million due to lower gross NGL production volumes of 113.8 Mgal/d from our Gathering and Processing segment and lower realized NGL prices of $0.50/gal, which is a decrease of $0.14/gal period over period,
- a decrease in natural gas revenue of $4.4 million due to lower realized natural gas prices of $2.23/Mcf, which is a decrease of $0.52/Mcf, or 18.9% period over period,
- a decrease in condensate revenues of $4.4 million due to higher condensate production of 4.4 Mgal/d offset by lower realized condensate prices of $0.91/gal, which is a decrease of $0.22/gal, or 19.5%, period over period, from our Gathering and Processing segment,
- a decrease in transportation revenue of $3.7 million due to lower throughput volumes in our Transmission segment, and
- a loss on commodity derivatives, net of $0.8 million compared to a gain on commodity derivatives, net of $0.3 million for the comparable quarter in 2015.

These decreases were partially offset by the following:

- an increase in fee-based oil gathering revenues of $3.1 million primarily due to incremental throughput volumes in our Gathering and Processing segment, and
- an increase in Terminals segment revenue of $1.3 million as a result of an increase in firm storage contracted capacity 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 June 30, 2016 were $22.1 million compared to $33.3 million for the three months ended June 30, 2015. This decrease of $11.2 million was due to lower NGL and natural gas purchases of $6.3 million and $4.7 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 throughput volumes related to our Gathering and Processing segment.

Gross Margin. Gross margin for the three months ended June 30, 2016 was $32.3 million and consistent with the three months ended June 30, 2015 primarily due to an increase in higher segment gross margin in our Terminals segment of $1.3 million, increases in our segment gross margin in our Gathering and Processing segment of $0.4 million as a result of higher average throughput volumes of 52.4 MMcf/d and incremental gross margin from American Panther of $4.3 million, which was offset by lower NGL production of 113.8 Mgal/d. The increases above being offset by lower segment gross margin in our Transmission segment of $1.7 million as a result of a decline in average transportation throughput volumes.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2016 were $16.2 million compared to $14.0 million in the three months ended June 30, 2015. This increase of $2.2 million was primarily due to $1.4 million of costs associated with our integrity management programs and environmental regulations, $0.6 million associated with employee severance payments, and higher insurance and property tax assessments of $0.8 million, which was partially offset by the timing of activities associated with lower compressor lease expense of $0.3 million as a result of our optimization project.

Selling, General and Administrative Expenses (SG&A). SG&A expenses for the three months ended June 30, 2016 were $11.4 million compared to $5.6 million for the three months ended June 30, 2015. This increase of $5.8 million was primarily due to an increase in transaction costs of $3.8 million, which include legal, accounting and other consulting services, related to recent acquisitions and our corporate relocation, higher salaries and wages of $0.5 million, and higher costs associated with systems and licenses of $0.5 million 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 June 30, 2016 was $1.0 million compared to $0.6 million for the three months ended June 30, 2015. This increase of $0.4 million was primarily due to the acceleration of equity and liability-based awards for certain executives.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended June 30, 2016 was $10.9 million compared to $9.3 million for the three months ended June 30, 2015. This increase of $1.6 million was primarily due to incremental depreciation of fixed assets related to our Bakken system which began operations in October 2015.

Interest Expense. Interest expense for the three months ended June 30, 2016 was $8.5 million compared to $3.6 million for the three months ended June 30, 2015. This increase of $4.9 million was primarily due to higher outstanding borrowings under the

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Credit Agreement, an increase in our weighted average interest rate of 0.6% and unfavorable unrealized losses on interest rate swaps.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the three months ended June 30, 2016 was $11.6 million compared to less than $0.1 million for the three months ended June 30, 2015. This increase of $11.6 million was due to incremental earnings of $7.2 million related to our investment in Delta House and earnings of $4.2 million from the interests in the entities underlying the Emerald Transactions which were acquired in April 2016.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Total Revenue. Our total revenue for the six months ended June 30, 2016 was $101.4 million compared to $132.1 million for the six months ended June 30, 2015. This decrease of $30.7 million was primarily due to the following:

- a decrease in NGL revenues of $13.2 million due to lower gross NGL production volumes of 95.0 Mgal/d from our Gathering and Processing segment and lower realized NGL prices of $0.45/gal, which is a decrease of $0.18/gal period over period,
- a decrease in condensate revenues of $10.6 million due to lower realized condensate prices of $0.79/gal, which is a decrease of $0.25/gal, or 24.0%, period over period, and lower condensate production of 10.7 Mgal/d from our Gathering and Processing segment,
- a decrease in natural gas revenue of $9.4 million due to lower realized natural gas prices of $2.24/Mcf, which is a decrease of $0.84/Mcf, or 27.3% period over period,
- a decrease in transportation revenue of $5.2 million due to lower throughput volumes in our Transmission segment, and
- a loss on commodity derivatives, net of $0.9 million compared to a gain on commodity derivatives, net of $0.5 million for the comparable quarter in 2015.

These decreases were partially offset by the following:

- an increase in crude oil gathering fee-based revenues of $4.5 million primarily due to incremental throughput volumes in our Gathering and Processing segment, and
- an increase in Terminals segment revenue of $1.8 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 six months ended June 30, 2016 were $39.0 million compared to $62.3 million for the six months ended June 30, 2015. This decrease of $23.3 million was due to lower NGL and natural gas purchases of $13.5 million and $10.6 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 six months ended June 30, 2016 was $59.8 million compared to $66.1 million for the six months ended June 30, 2015. This decrease of $6.3 million was primarily due to a decrease in segment gross margin in our Gathering and Processing segment of $5.0 million, as a result of lower NGL and condensate production of 95.0 Mgal/d and 10.7 Mgal/d, respectively, and lower average throughput volumes of 9.5 MMcf/d, as well as lower segment gross margin in our Transmission segment of $3.1 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 $1.8 million and incremental gross margin from American Panther of $4.3 million.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2016 were $30.7 million compared to $27.8 million in the six months ended June 30, 2015. This increase of $2.9 million was primarily due to

$1.9 million of costs associated with our integrity management programs and environmental regulations, higher insurance and property tax assessments of $0.8 million, and higher salaries and wages of $0.5 million.

Selling, General and Administrative Expenses (SG&A). SG&A expenses for the six months ended June 30, 2016 were $20.0 million compared to $12.5 million for the six months ended June 30, 2015. This increase of $7.5 million was primarily due to an increase in transaction costs of $4.6 million, some of which is non-recurring, include legal, accounting and other consulting services, related to recent acquisitions and the corporate relocation, higher costs associated with systems and licenses of $0.8 million due to an increase in information and technology maintenance costs primarily related to systems that were implemented in the prior year, higher salaries and wages of $0.7 million due to increased headcount and higher legal and regulatory compliance fees of $0.5 million.

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Equity Compensation Expense. Equity compensation expense related to our Long-Term Incentive Plan for the six months ended June 30, 2016 was $2.1 million compared to $2.2 million for the six months ended June 30, 2015. This decrease of $0.1 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 six months ended June 30, 2016 was $21.0 million compared to $18.9 million for the six months ended June 30, 2015. This increase of $2.1 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 six months ended June 30, 2016 was $14.4 million compared to $6.2 million for the six months ended June 30, 2015. This increase of $8.2 million was primarily due to higher outstanding borrowings under the Credit Agreement, an increase in our weighted average interest rate of 1.2% and unfavorable unrealized losses on interest rate swaps.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the six months ended June 30, 2016 was $19.0 million compared to $0.2 million for the six months ended June 30, 2015. This increase of $18.8 million was primarily due to incremental earnings of $14.3 million related to our investment in Delta House and $4.2 million related to the interests in the entities underlying the Emerald Transactions, which were acquired in April 2016.

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 June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$41,780	$50,439	$72,928	$98,888
Gain (loss) on commodity derivatives, net	(764)	311	(867)	458
Total revenue	41,016	50,750	72,061	99,346
Purchases of natural gas, NGLs and condensate	20,964	30,272	36,412	57,590
Direct operating expenses	11,231	9,130	21,234	18,223
Other financial data:				
Segment gross margin (b)	$20,605	$20,219	$36,336	$41,265
Operating data:				
Average throughput (MMcf/d)	386.5	334.1	360.3	350.8
Average plant inlet volume (MMcf/d) (a)	101.2	120.0	102.4	128.0
Average gross NGL production (Mgal/d) (a)	217.3	331.1	206.4	301.4
Average gross condensate production (Mgal/d) (a)	100.2	95.8	86.9	97.6
Average realized prices:				
Natural gas ($/Mcf)	$2.23	$2.75	$2.24	$3.08
NGLs ($/gal)	$0.50	$0.64	$0.45	$0.63
Condensate ($/gal)	$0.91	$1.13	$0.79	$1.04

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

(b) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

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Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Revenue. Segment total revenue for the three months ended June 30, 2016 was $41.0 million compared to $50.8 million for the three months ended June 30, 2015. This decrease of $9.8 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 18.9%, 21.9%, and 19.5%, respectively,
- lower average NGL production of 113.8 Mgal/d primarily due to a decrease in off-spec NGL volumes received and processed at our Longview system, offset by
- higher average throughput volumes of 52.4 MMcf/d, period over period, primarily due to incremental volumes associated with our acquired Gulf of Mexico Pipeline.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended June 30, 2016 were $21.0 million compared to $30.3 million for the three months ended June 30, 2015. This decrease of $9.3 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 June 30, 2016 was $20.6 million compared to $20.2 million for the three months ended June 30, 2015. This increase of $0.4 million was primarily due to incremental gross margin from American Panther of $4.3 million and expenses of $1.5 million on the Bakken crude oil system which commenced operations in April 2016 and October 2015, respectively, offset by lower gross margin of $3.1 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 $1.2 million at our Lavaca System due to contractually lower compression fees and lower contracted condensate sales.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2016 were $11.2 million compared to $9.1 million for the three months ended June 30, 2015. This increase of $2.1 million was primarily due to incremental operating expenses associated with American Panther system of $1.0 million and expenses of the Bakken crude oil system of $0.8 million that commenced operations in April 2016 and October 2015, respectively.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Revenue. Segment total revenue for the six months ended June 30, 2016 was $72.1 million compared to $99.3 million for the six months ended June 30, 2015. This decrease of $27.2 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 27.3%, 28.6%, and 24.0%, respectively,
- lower average NGL and condensate production of 95.0 Mgal/d and 10.7 Mgal/d, respectively, primarily due to a decrease in off-spec NGL and condensate volumes received and processed at our Longview system, offset by
- higher average throughput volumes of 9.5 MMcf/d, period over period, primarily due to incremental volumes associated with our acquired Gulf of Mexico Pipeline.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the six months ended June 30, 2016 were $36.4 million compared to $57.6 million for the six months ended June 30, 2015. This decrease of $21.2 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 six months ended June 30, 2016 was $36.3 million compared to $41.3 million for the six months ended June 30, 2015. This decrease of $5.0 million was primarily due to lower gross margin of $7.2 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 $2.6 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 from American Panther of $4.3 million and $3.0 million on the Bakken crude oil system which commenced operations in April 2016 and October 2015, respectively.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2016 were $21.2 million compared to $18.2 million for the six months ended June 30, 2015. This increase of $3.0 million was primarily due to incremental operating

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expenses associated with the American Panther system of $1.0 million and expenses of the Bakken crude oil system of $1.8 million that commenced operations in April 2016 and October 2015, respectively.

Transmission Segment

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Transmission segment				
Financial data:				
Total revenue	$8,738	$12,423	$18,965	$24,171
Purchases of natural gas, NGLs and condensate	1,138	3,062	2,602	4,721
Direct operating expenses	3,425	3,253	6,266	6,432
Other financial data:				
Segment gross margin (a)	$7,593	$9,333	$16,348	$19,394
Operating data:				
Average throughput (MMcf/d)	633.2	697.1	662.8	753.7
Average firm transportation - capacity reservation (MMcf/d)	402.7	656.7	573.5	675.9
Average interruptible transportation - throughput (MMcf/d)	373.4	415.2	385.2	430.3

(a) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Revenue. Segment total revenue for the three months ended June 30, 2016 was $8.7 million compared to $12.4 million for the three months ended June 30, 2015. This decrease of $3.7 million in segment revenue was primarily due to lower average throughput volumes of 63.9 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 June 30, 2016 of $1.1 million compared to $3.1 million for the three months ended June 30, 2015. This decrease of $2.0 million was primarily due to lower volumetric throughput and a decline in realized natural gas prices of $0.52 associated with our fixed margin arrangements.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2016 was $7.6 million compared to $9.3 million for the three months ended June 30, 2015. This decrease of $1.7 million was primarily due to the lower average throughput volumes of 63.9 MMcf/d, or 9.2%, noted above, and lower interruptible transportation margins, period over period.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2016 were $3.4 million compared with the $3.3 million for the three months ended June 30, 2015. This increase of $0.1 million was primarily related to the timing of activities associated with our integrity management and maintenance programs, period over period.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Revenue. Segment total revenue for the six months ended June 30, 2016 was $19.0 million compared to $24.2 million for the six months ended June 30, 2015. This decrease of $5.2 million in segment revenue was primarily due to lower average throughput volumes of 90.9 MMcf/d primarily attributable to our Midla and High Point systems.

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Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2016 of $2.6 million compared to $4.7 million for the six months ended June 30, 2015. This decrease of $2.1 million was primarily due to lower volumetric throughput and a decline in realized natural gas prices of $0.84 associated with our fixed margin arrangements.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2016 was $16.3 million compared to $19.4 million for the six months ended June 30, 2015. This decrease of $3.1 million was primarily due to the lower average throughput volumes of 90.9 MMcf/d, or 12.1%, noted above, and lower interruptible transportation margins, period over period.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2016 were $6.3 million compared with the $6.4 million for the six months ended June 30, 2015. This decrease of $0.1 million was primarily related to the timing of activities associated with our integrity management and maintenance program, period over period.

Terminals Segment

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Terminals segment				
Financial data:				
Total revenue	$5,628	$4,336	$10,376	$8,601
Direct operating expenses	1,535	1,584	3,212	3,179
Other financial data:				
Segment gross margin (b)	$4,093	$2,752	$7,164	$5,422
Operating data:				
Contracted Capacity (Bbls)	2,018,233	1,449,067	1,768,767	1,386,567
Design Capacity (Bbls)	2,150,800	1,667,467	1,975,800	1,585,433
Storage utilization (a)	93.8 %	86.9 %	89.5 %	87.5 %

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

(b) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Revenue. Segment total revenue for the three months ended June 30, 2016 was $5.6 million compared to $4.3 million for the three months ended June 30, 2015. The increase of $1.3 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 June 30, 2016 of $1.5 million was consistent with the $1.6 million of direct operating expenses for the three months ended June 30, 2015.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2016 was $4.1 million compared to $2.8 million for the three months ended June 30, 2015. The increase of $1.3 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Revenue. Segment total revenue for the six months ended June 30, 2016 was $10.4 million compared to $8.6 million for the six months ended June 30, 2015. The increase of $1.8 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.

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Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2016 of $3.2 million was consistent with the $3.2 million of direct operating expenses for the six months ended June 30, 2015.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2016 was $7.2 million compared to $5.4 million for the six months ended June 30, 2015. The increase of $1.8 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 cash from operating activities, 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 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 six months ended June 30, 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 through the quarter ended June 30, 2016. Our liquidity in that period was also impacted by borrowings under our Credit Agreement to fund ongoing 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 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 June 30, 2016, we have not been required to post collateral with our counterparties.

At-The-Market ("ATM") Offering

On October 18, 2015, we filed a prospectus supplement related to the offer and sale from time to time of common units in an at-the-market offering. For the six months ended June 30, 2016, we sold 248,561 common units for proceeds of $3.2 million, net of commissions and accrued offering costs of less than $0.1 million, which were used for general partnership purposes including the repayment of amounts outstanding under the Credit Agreement, the funding of acquisitions, and the funding of capital expenditures. As of June 30, 2016, approximately $96.8 million remained available for sale under the Partnership's ATM Equity Offering Sales Agreement.

Our Credit Facility

Effective as of April 25, 2016, the Partnership entered into the Second Amendment to the Amended and Restated Credit Agreement (as amended, the Credit Agreement), which provides for maximum borrowings equal to $750.0 million, with the ability to further

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increase the borrowing capacity to $900.0 million subject to lender approval. The Credit Agreement contains certain financial covenants, including i) a consolidated total 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, 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 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 events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

As of June 30, 2016 our consolidated total leverage ratio was 4.15 and our interest coverage ratio was 8.86, which were in compliance with the financial covenants required in the Credit Agreement. The maximum permitted consolidated total leverage ratio was 4.75 for the twelve month period ended June 30, 2016. As of June 30, 2016, we had approximately $672.4 million of outstanding borrowings under the Credit Agreement.

At June 30, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $5.4 million and $1.8 million, respectively.

As of June 30, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the consolidated total leverage and minimum 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

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 $10.3 million at June 30, 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):

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	Six months ended June 30,	
	2016	2015
Net cash provided by (used in):		
Operating activities	$18,677	$29,620
Investing activities	(138,802)	(61,297)
Financing activities	120,879	31,526

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Operating Activities. Net cash provided by operating activities was $18.7 million for the six months ended June 30, 2016 compared to $29.6 million for the six months ended June 30, 2015. Net cash provided by operating activities for the six months ended June 30, 2016 decreased by $10.9 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 $2.9 million and $7.5 million, respectively, an increase in interest expense of $8.2 million primarily due to higher outstanding borrowings and an unfavorable change in operating assets and liabilities of $7.7 million.

These decreases in operating cash flows were partially offset by an increase in earnings from unconsolidated affiliates of $18.8 million due to the acquisition of our interests in the entities underlying the Emerald Transactions.

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 $138.8 million for the six months ended June 30, 2016 compared to $61.3 million for the six months ended June 30, 2015. Cash used in investing activities for the six months ended June 30, 2016 increased by $77.5 million primarily due to funds used to acquire our interests underlying the Emerald Transactions of $100.9 million, higher cash contributions of $10.8 million related to investments in unconsolidated affiliates period over period, higher costs of acquisitions of $10.5 million 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 $3.7 million received during the first quarter of 2015.

These increases in cash used in investing activities were partially offset by lower capital expenditures of $39.5 million as a result of a decrease in growth capital projects in process and higher cash distributions received from investments in unconsolidated affiliates as a return of capital of $15.4 million.

Financing Activities. Net cash provided by financing activities was $120.9 million for the six months ended June 30, 2016 compared to $31.5 million for the six months ended June 30, 2015. Cash provided by financing activities for the six months ended June 30, 2016 increased by $89.4 million primarily due to higher net borrowings on our Credit Agreement of $133.2 million associated with the acquisitions of interests in the entities underlying the Emerald Transactions, the acquisition of an additional investment in Delta House and the acquisition by American Panther.

This increase in cash provided by financing activities was partially offset by the issuance of Series A-2 units for gross proceeds of $45.0 million in the second quarter of 2015 while there were no issuance of Series A-2 units in the second quarter of 2016.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At June 30, 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 June 30, 2016, our off-balance sheet arrangements changed by $15.9 million, as a result of the executed 16-year office sublease, 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

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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 six months ended June 30, 2016, capital expenditures totaled $40.2 million, including expansion capital expenditures of $38.5 million, maintenance capital expenditures of $0.9 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 $0.8 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.

Distributions

We intend to pay a quarterly distribution for the foreseeable future although we do not have a legal obligation to make distributions except as provided in our Partnership Agreement.

On July 21, 2016, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per unit for the second quarter ended June 30, 2016, or $1.65 per unit on an annualized basis. The cash distribution is expected to be paid on August 12, 2016, to unitholders of record as of the close of business on August 3, 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 June 30, 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 5 "Derivatives" for further details.

As of June 30, 2016, we economically hedged approximately 43% of our expected exposure to NGL prices and 56% 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 June 30, 2016:

Commodity	Instrument	Volumes (a)	Weighted Average Price	Period

					Fair value at June 30, 2016 (in thousands)
NGLs (gal)	Swaps	(4,609,200)	$0.63	July 2016 - December 2016	$ (499)
Oil (Bbl)	Swaps	(22,540)	$44.22	July 2016 - December 2016	(126)
					$ (625)

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

Interest Rate Risk

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During the six months ended June 30, 2016, we had exposure to changes in interest rates on our indebtedness outstanding under 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. On June 17, 2016, we entered into interest rate swaps with a notional amount of $100.0 million that will expire in December 31, 2021.

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 $3.0 million for the six months ended June 30, 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 June 30, 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 June 30, 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.

Item 6. Exhibits

Exhibit Number	Exhibit
2.1	Purchase and Sale Agreement by and between Emerald Midstream, LLC and American Midstream Emerald, LLC dated April 25, 2016 (filed as Exhibit 2.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
2.2	Purchase and Sale Agreement by and between Emerald Midstream, LLC and American Midstream Emerald, LLC dated April 27, 2016 (filed as Exhibit 2.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
2.3	Unit Purchase Agreement by and between Magnolia Infrastructure Holdings, LLC and American Midstream Delta House, LLC dated April 25, 2016 (filed as Exhibit 2.3 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
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	First Amendment to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated June 21, 2016 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on June 22, 2016).
3.4	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).
3.5	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).
10.1	Securities Purchase Agreement by and between American Midstream Partners, LP and Magnolia Infrastructure Partners, LLC dated April 25, 2016 (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
10.2	Second Amendment to Amended and Restated Credit Agreement and First Amendment to Amended and Restated Guaranty and Collateral, dated April 25, 2016 (filed as Exhibit 10.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
10.3	Warrant issued by American Midstream Partners, LP, dated April 25, 2016 (filed as Exhibit 10.3 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
10.4	Class C Membership Interest Award Agreement, dated May 2, 2016 (filed as Exhibit 10.1 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 June 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the June 30, 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 June 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the June 30, 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

*	Furnished herewith.
**	Submitted electronically herewith.

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SIGNATURES
Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
Date: August 8, 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/ Eric T. Kalamaras
Name: Eric T. Kalamaras
Title: Senior Vice President & Chief Financial Officer
(principal financial officer)

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