American Midstream Partners, LP
Form 10-Q
November 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
September 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.)

2103 CityWest Blvd., Bldg. 4, Suite 800
Houston, TX 77042
(Address of principal executive offices) (Zip code)
(713) 815-3900
(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 31,237,021 common units, 9,951,195 Series A Units, 8,664,468 Series C Units and 2,333,333 Series D Units of American Midstream Partners, LP outstanding as of November 3, 2016. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

TABLE OF CONTENTS

		Page
PART I. FINANCIAL INFORMATION		4
Item 1.	Financial Statements (Unaudited)	4
	Condensed Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015	4
	Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2016 and 2015	6
	Condensed Consolidated Statements of Comprehensive Income (Loss) for the three and nine months ended September 30, 2016 and 2015	7
	Condensed Consolidated Statements of Changes in Partners' Capital and Noncontrolling Interests as of and for the nine months ended September 30, 2016 and 2015	8
	Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2016 and 2015	9
	Notes to Condensed Consolidated Financial Statements	11
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	38
	Cautionary Statement About Forward-Looking Statements	38
	Overview	39
	Recent Developments	40
	Our Operations	42
	How We Evaluate Our Operations	45
	Results of Operations - Combined Overview	48
	Liquidity and Capital Resources	56
	Critical Accounting Policies	60
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	61
Item 4.	Controls and Procedures	63
PART II. OTHER INFORMATION		64
Item 1.	Legal Proceedings	64
Item 1A.	Risk Factors	64
Item 6.	Exhibits	66

Table of Contents

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.

Table of Contents

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

	September 30, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$ 4,879	$ —
Accounts receivable, net of allowance for doubtful accounts of $135 and $0, respectively	8,309	3,181
Unbilled revenue	20,126	15,559
Risk management assets	687	365
Other current assets	8,883	10,094
Total current assets	42,884	29,199
Property, plant and equipment, net	699,978	648,013
Goodwill	16,262	16,262
Intangible assets, net	97,702	100,965
Investment in unconsolidated affiliates	284,485	82,301
Other assets, net	57,816	14,556
Total assets	$ 1,199,127	$ 891,296
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$ 3,878	$ 4,667
Accrued gas purchases	9,185	7,281
Accrued expenses and other current liabilities	48,281	25,035
Current portion of senior notes and debt	1,351	2,338
Risk management liabilities	604	—
Total current liabilities	63,299	39,321
Risk management liabilities	826	—
Asset retirement obligations	43,876	28,549
Other liabilities	303	1,001
Senior notes	56,395	—
Long-term debt	672,694	525,100
Deferred tax liability	7,102	5,826
Total liabilities	844,495	599,797
Commitments and contingencies (See Note 16)		
Convertible preferred units		
Series A convertible preferred units (9,951 thousand and 9,210 thousand units issued and outstanding as of September 30, 2016 and December 31, 2015, respectively)	178,653	169,712
Series C convertible preferred units (8,664 thousand and zero units issued and outstanding as of September 30, 2016 and December 31, 2015, respectively)	118,229	—
Equity and partners' capital (deficit)		
General Partner interests (672 thousand and 536 thousand units issued and outstanding as of September 30, 2016 and December 31, 2015, respectively)	(105,483)	(104,853)
Limited Partner interests (31,195 thousand and 30,427 thousand units issued and outstanding as of September 30, 2016 and December 31, 2015, respectively)	153,975	188,477

Table of Contents

Series B convertible units (zero and 1,350 thousand units issued and outstanding as of September 30, 2016 and December 31, 2015, respectively)	—	33,593
Accumulated other comprehensive income	73	40
Total partners' capital	48,565	117,257
Noncontrolling interests	9,185	4,530
Total equity and partners' capital	57,750	121,787
Total liabilities, equity and partners' capital	$1,199,127	$891,296

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

Table of Contents

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

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Revenue	$63,671	$54,825	$165,942	$186,485
Gain (loss) on commodity derivatives, net	147	816	(722)	1,274
Total revenue	63,818	55,641	165,220	187,759
Operating expenses:				
Purchases of natural gas, NGLs and condensate	26,082	24,431	65,096	86,742
Direct operating expenses	16,042	15,328	46,754	43,162
Selling, general and administrative expenses	13,289	7,639	33,255	20,145
Equity compensation expense	104	574	2,213	2,822
Depreciation, amortization and accretion expense	11,018	9,160	32,015	28,099
Total operating expenses	66,535	57,132	179,333	180,970
Gain (loss) on sale of assets, net	—	(32)	90	(3,010)
Operating income (loss)	(2,717)	(1,523)	(14,023)	3,779
Other income (expense):				
Interest expense	(5,156)	(3,553)	(19,535)	(9,719)
Earnings in unconsolidated affiliates	10,993	1,094	29,983	1,265
Income (loss) from continuing operations before taxes	3,120	(3,982)	(3,575)	(4,675)
Income tax expense	(441)	(592)	(1,301)	(1,065)
Income (loss) from continuing operations	2,679	(4,574)	(4,876)	(5,740)
Loss from discontinued operations, net of tax	—	(53)	—	(79)
Net income (loss)	2,679	(4,627)	(4,876)	(5,819)
Less: Net income attributable to noncontrolling interests	1,196	34	2,175	80
Net income (loss) attributable to the Partnership	$1,483	$(4,661)	$(7,051)	$(5,899)
General Partner's interest in net income (loss)	$19	$(60)	$(94)	$(76)
Limited Partners' interest in net income (loss)	$1,464	$(4,601)	$(6,957)	$(5,823)
Distribution declared per common unit (1)	$0.4125	$0.4725	$1.2975	$1.4175
Limited Partners' net loss per common unit (See Note 13):				
Basic and diluted	$(0.22)	$(0.48)	$(0.91)	$(1.02)
Weighted average number of common units outstanding:				
Basic and diluted	31,168	23,987	30,979	23,154

(1) Distributions declared and paid each quarter related to prior quarter's earnings.

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

Table of Contents

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

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Net income (loss)	$2,679	$(4,627)	$(4,876)	$(5,819)
Unrealized gain (loss) related to postretirement benefit plan	(2)	10	33	(24)
Comprehensive income (loss)	2,677	(4,617)	(4,843)	(5,843)
Less: Comprehensive income attributable to noncontrolling interests	1,196	34	2,175	80
Comprehensive income (loss) attributable to the Partnership	$1,481	$(4,651)	$(7,018)	$(5,923)

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

Table of Contents

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 Interests
Balances at December 31, 2014	$(2,450)	$294,695	$ 32,220	$ 2	$324,467	$ 4,717
Net income (loss)	(76)	(5,823)	—	—	(5,899)	80
Issuance of common units, net of offering costs	—	80,971	—	—	80,971	—
Issuance of Series B units	—	—	1,157	—	1,157	—
Unitholder contributions	1,973	—	—	—	1,973	—
Unitholder distributions	(4,890)	(45,800)	—	—	(50,690)	—
Unitholder distributions for Delta House	(100,649)	—	—	—	(100,649)	—
Net distributions to noncontrolling interests	—	—	—	—	—	(101)
Acquisitions of noncontrolling interests	—	(20)	—	—	(20)	(172)
LTIP vesting	(2,404)	2,599	—	—	195	—
Tax netting repurchase	—	(755)	—	—	(755)	—
Equity compensation expense	2,627	—	—	—	2,627	—
Other comprehensive loss	—	—	—	(24)	(24)	—
Balances at September 30, 2015	$(105,869)	$325,867	$ 33,377	$ (22)	$253,353	$ 4,524
Balances at December 31, 2015	$(104,853)	$188,477	$ 33,593	$ 40	$117,257	$ 4,530
Net income (loss)	(94)	(6,957)	—	—	(7,051)	2,175
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B units	—	33,593	(33,593)	—	—	—
Issuance of Warrant	4,481	—			4,481	
Issuance of common units, net of offering costs	—	2,955	—	—	2,955	—
Unitholder contributions	1,901	—	—	—	1,901	—
Unitholder distributions	(7,637)	(60,092)	—	—	(67,729)	—
Unitholder contribution for acquisitions	990	—	—	—	990	—
Net contributions from noncontrolling interests	—	—	—	—	—	649
Acquisition of Gulf of Mexico Pipeline	—	—	—	—	—	1,831
LTIP vesting	(3,163)	3,163	—	—	—	—
Tax netting repurchase	—	(347)	—	—	(347)	—
Equity compensation expense	2,892	—	—	—	2,892	—
Other comprehensive income	—	—	—	33	33	—
Balances at September 30, 2016	$(105,483)	$153,975	$ —	$ 73	$48,565	$ 9,185

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

Table of Contents

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

	Nine months ended September 30,	
	2016	2015
Cash flows from operating activities		
Net loss	$(4,876)	$(5,819)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	32,015	28,099
Amortization of deferred financing costs	1,603	1,029
Amortization of weather derivative premium	708	694
Unrealized (gain) loss on derivatives, net	1,430	(523)
Non-cash compensation	2,892	2,891
Postretirement expense	—	55
(Gain) loss on sale of assets, net	(90)	3,160
Earnings in unconsolidated affiliates	(29,983)	(1,265)
Distributions from unconsolidated affiliates	29,513	1,265
Deferred tax expense	1,276	876
Allowance for doubtful accounts	135	—
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	(5,263)	(42)
Unbilled revenue	(4,567)	8,554
Risk management assets and liabilities	(1,030)	(875)
Other current assets	1,211	1,996
Other assets, net	751	21
Accounts payable	(213)	(3,847)
Accrued gas purchases	1,904	(6,445)
Accrued expenses and other current liabilities	10,207	1,652
Asset retirement obligations	(598)	—
Other liabilities	(698)	155
Net cash provided by operating activities	36,327	31,631
Cash flows from investing activities		
Acquisitions, net of cash acquired and settlements	(2,676)	7,383
Acquisition of investments in unconsolidated affiliates	(100,908)	—
Additions to property, plant and equipment	(65,906)	(111,864)
Proceeds from disposals of property, plant and equipment	137	4,797
Investment in unconsolidated affiliates	(13,099)	(64,406)
Distributions from unconsolidated affiliates, return of capital	33,284	5,303
Restricted cash	(43,691)	6,475
Net cash used in investing activities	(192,859)	(152,312)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	2,910	80,983
Unitholder contributions	1,901	1,905
Unitholder distributions	(46,740)	(36,935)
Issuance of Series A Units, net of issuance costs	—	45,000
Series C Units issuance costs	(62)	—

Unitholder distributions for Delta House	—	(100,649)

9

Table of Contents

Acquisition of noncontrolling interests	1,831	(74)
Net contributions from (distributions to) noncontrolling interests	649	(101)
LTIP tax netting unit repurchase	(347)	(755)
Deferred financing costs	(3,987)	(1,984)
Proceeds from senior notes	60,000	—
Payments on other debt	(2,337)	(2,908)
Repayments under Credit Agreement	(122,650)	(152,000)
Borrowings under Credit Agreement	270,243	287,700
Net cash provided by financing activities	161,411	120,182
Net increase (decrease) in cash and cash equivalents	4,879	(499)
Cash and cash equivalents		
Beginning of period	—	499
End of period	$4,879	$—
Supplemental cash flow information:		
Interest payments, net of capitalized interest	$17,186	$7,606
Supplemental non-cash information:		
Increase (decrease) in accrued property, plant and equipment	$3,616	$(24,666)
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	11,429	12,598
Accrued and paid-in-kind unitholder distribution for Series C Units	4,559	—
Paid-in-kind unitholder distribution for Series B Units	—	1,157
Cancellation of escrow units	6,817	—
Accrued distribution	5,000	—

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

Table of Contents

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 operate more than 3,000 miles of pipelines that gather and transport over 1.1 Bcf/d of natural gas and operate approximately 2.4 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 nine months ended September 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").

The accompanying unaudited 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 consolidation.

Investment in Unconsolidated Affiliates

We hold various non-operated membership interests in entities that own and operate natural gas pipeline systems and 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 of which is not the primary beneficiary, are accounted for using the equity method and are reported in Investment in unconsolidated affiliates in the accompanying unaudited 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.

Table of Contents

Restricted cash and cash equivalents

On September 30, 2016, Midla Financing, LLC ("Midla Financing"), American Midstream (Midla), LLC ("Midla"), and Mid Louisiana Gas Transmission LLC, ("MLGT" and, together with Midla, the "Note Guarantors"), each an indirect subsidiary of the Partnership entered into a Note Purchase and Guaranty Agreement (the "3.77% Senior Note Purchase Agreement") with institutional investors in which Midla Financing sold $60 million in aggregate principal amount of senior secured notes due June 30, 2031 that bear interest at a rate of 3.77% per annum (the "3.77% Senior Notes"). The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million (after deducting related issuance costs). On September 30, 2016, we used $14.0 million of the proceeds to pay down a portion of our Credit Agreement (as defined herein). The remainder of the net proceeds are contractually restricted and will be used to fund the retirement of Midla's existing 1920's vintage pipeline and the construction of a new replacement pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the "Midla-Natchez Line"). The 3.77% Senior Note Purchase Agreement allows the Partnership to reimburse itself for cash previously spent on the retirement of the former Midla pipeline and construction of the Midla-Natchez Line. As of September 30, 2016, we had restricted cash of $43.7 million. Please read Note 12 - Debt Obligations - 3.77% Senior Notes and Note 16 - Commitments and Contingencies for further discussion. We have included the net proceeds in Other assets on our unaudited condensed consolidated balance sheet. Construction on the Midla-Natchez Line commenced in the second quarter of 2016 and we expect service to begin in the first six months of 2017.

Allowance for doubtful accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding receivables balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of September 30, 2016, the Partnership recorded allowances for doubtful accounts of $0.1 million. As of December 31, 2015, the Partnership did not record an allowance for doubtful accounts.

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 our estimates.

New Accounting Pronouncements

Accounting Standards Issued and Adopted

In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments, which clarifies existing guidance for assessing embedded call (put) options that are closely related to their debt hosts using a four-step

decision sequence. ASU No. 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 adopted 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): Simplifying the
Transition to the Equity Method of Accounting, which 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 No. 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 adopted this guidance and determined it will not have a material impact on its consolidated financial statements and related disclosures.

Table of Contents

Accounting Standards Issued Not Yet Adopted

In May 2014, the FASB issued 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 No. 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 No. 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 No. 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 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. ASU No. 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. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee
Share-Based Payment Accounting. 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 No. 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal periods. 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 June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, which requires financial assets measured at amortized cost basis to be presented at the net amount expected to be collected. The new standard applies to trade receivables and requires expected credit losses to be based on past events, current conditions and reasonable and supportable forecasts that affect the instrument’s collectability. ASU No. 2016-13 is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal periods. Early adoption is permitted. The Partnership is currently evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 320): Classification of Cash Receipts and Cash Payments, which addresses eight specific cash flow issues with the objective of reducing the existing diversity of presentation and classification in the statement of cash flows. The new standard applies to cash flows associated with debt payment or debt extinguishment costs, settlement of zero-coupon debt or other debt instruments with coupon rates that are insignificant in relation to effective interest rate of borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU No. 2016-15 is effective for fiscal years beginning after December 15, 2017,

including interim periods within those fiscal periods. Early adoption is permitted, but only if all amendments are adopted in the same period. The Partnership is currently evaluating the 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

Table of Contents

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, and 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. We became the operator of the Destin pipeline on November 1, 2016. The Tri-States pipeline is a FERC-regulated, 161-mile 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.We became the operator of the Okeanos pipeline on November 1, 2016.

The Partnership funded the aggregate purchase price for the Emerald Transactions with the issuance of 8,571,429 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 unaudited condensed consolidated balance sheets, and as an investing activity of $100.9 million within the unaudited 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 unaudited condensed consolidated statements of changes in partners' capital and noncontrolling interests.

For the three and nine months ended September 30, 2016, the Partnership recorded $2.5 million and $6.7 million in earnings, respectively, and received cash distributions of $12.5 million and $17.9 million, respectively, 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 unaudited condensed consolidated statements of cash flows.

Gulf of Mexico Pipeline

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 $2.7 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 estimated fair values as of the acquisition date.

Table of Contents

The fair value of these assets and liabilities are measured on a nonrecurring basis and are classified as Level 3 within the fair value hierarchy.

During the three months ended September 30, 2016, there was a reduction in the purchase price of $0.4 million which resulted in a corresponding decrease in the amount allocated to property, plant, and equipment. The following table summarizes the fair value of consideration transferred by the Partnership for the acquisition and the adjusted allocation of the purchase price to the assets acquired based on their respective fair values as of the acquisition date (in thousands):

Fair value of consideration transferred:		
Cash	$2,676	
Fair value of assets acquired, liabilities assumed:		
Assets:		
Property, plant and equipment:		
Pipelines		$16,555
Land		421
Total property, plant and equipment		16,976
Liabilities:		
Asset retirement obligations		(14,300)
Fair value of net assets acquired and liabilities assumed		$2,676

American Panther contributed revenues of $4.6 million and $8.9 million and net income of $2.7 million and $5.3 million for the three and nine months ended September 30, 2016, respectively, which are included in the Partnership's Gathering and Processing segment. During the nine months ended September 30, 2016, the Partnership incurred $0.2 million of transaction costs related to the acquisition which are included in Selling, general and administrative expenses in our unaudited condensed consolidated statements of operations for the periods. We incurred immaterial transaction costs related to the acquisition during the three months ended September 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 ("FPS Equity") and (ii) 53.5 Class A Units of Delta House Oil and Gas Lateral LLC (collectively, the "D-Day investment") in exchange for a cash purchase price of approximately $9.9 million funded with additional borrowings under the Partnership's Credit Agreement (as defined herein). 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 on our unaudited condensed consolidated balance sheets and as an investing activity within the unaudited condensed consolidated statements of cash flows. For the three and nine months ended September 30, 2016, the Partnership recorded $0.5 million and $0.9 million in earnings from the D-Day investment, respectively. The Partnership received distributions from the D-Day investment of $0.9 million and $2.0 million for the three and nine months ended September 30, 2016, respectively. 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 unaudited 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 non-operated direct and indirect interests in Delta House of 13.9%, as of September 30, 2016. Please read Note 19 - Subsequent Events for our acquisition of an additional non-operated direct interest in Delta House in October 2016. Pursuant to the agreements governing the underlying entities, we have no management

Table of Contents

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 unaudited condensed consolidated financial statements.

Divestitures

On September 14, 2015, the Partnership disposed of certain terminal assets in Salisbury, Maryland that were previously held for sale, with a book value approximating the sales proceeds of $0.9 million, resulting in a non-cash loss on disposal of less than $0.1 million. Of the proceeds received, the Partnership distributed $0.4 million to our General Partner.

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 producers of crude oil, natural gas, NGLs, condensate and specialty chemicals (our customers) 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. For both the three and nine months ended September 30, 2016 we recognized bad debt expense of $0.1 million and for the three and nine months ended 2015, no allowances were recorded.

During the three and nine months ended September 30, 2016, one customer accounted for 13% and 12%, respectively, of the Partnership's consolidated revenue. During the three months ended September 30, 2015, one customer accounted for 12% of the Partnership's consolidated revenue. During the nine months ended September 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):

	September 30, 2016	December 31, 2015
Prepaid insurance	$ 1,370	$ 3,948
Other receivables	1,793	1,573
Gas imbalance receivable	1,901	—
Other prepaid amounts	1,000	2,866
Other current assets	2,819	1,707
Total	$ 8,883	$ 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 September 30, 2016, the aggregate notional volume of our commodity derivatives was 2.7 million gallons of NGLs, natural gas and crude oil equivalent for 2016 production.

Table of Contents

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 September 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 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 (as defined herein), 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 September 30, 2016, the total notional amount of our interest rate swaps was $300.0 million.

In the first quarter of 2016, we entered into an interest rate swap with a notional amount of $200.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap is effective beginning January 3, 2017 and will expire September 3, 2019.

In the second quarter of 2016, we entered into additional interest rate swap with a notional amount of $100.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap is 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 nine months ended September 30, 2016 and 2015, respectively, which were recorded as current Risk management assets on our unaudited condensed consolidated balance sheets 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 $0.7 million and $0.4 million as of September 30, 2016 and December 31, 2015.
As of September 30, 2016 and December 31, 2015, the value associated with our commodity derivatives, interest rate swaps and weather derivative were recorded on our unaudited condensed consolidated balance sheets as follows (in thousands):

	Gross Risk Management Assets		Gross Risk Management Liabilities		Net Risk Management Assets (Liabilities)	
Balance Sheet Classification	September 30, 2016	December 31, 2015	September 30, 2016	December 31, 2015	September 30, 2016	December 31, 2015
Current	$ 687	$ 365	$ —	$ —	$687	$ 365
Non current	—	—	—	—	—	—
Total assets	$ 687	$ 365	$ —	$ —	$687	$ 365

Current	$ —	$ —	$ (604)	$ —	$(604)	$ —
Non current	—	—	(826)	—	(826)	—
Total liabilities	$ —	$ —	$ (1,430)	$ —	$(1,430)	$ —

Table of Contents

For the three and nine months ended September 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 unaudited condensed consolidated statements of operations as follows (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	Gain (Loss) on Derivatives		Gain (Loss) on Derivatives	
Statement of Operations Classification	Realized	Unrealized	Realized	Unrealized
2016				
Gain (loss) on commodity derivatives, net	$(169)	$ 316	$(413)	$ (309)
Interest expense	—	1,642	—	(1,121)
Direct operating expenses	(258)	—	(708)	—
Total	$(427)	$ 1,958	$(1,121)	$ (1,430)
2015				
Gain on commodity derivatives, net	$575	$ 241	$966	$ 308
Interest income (expense)	(36)	69	(240)	215
Direct operating expenses	(219)	—	(694)	—
Total	$320	$ 310	$32	$ 523

6. Fair Value Measurement

We apply the market approach for recurring fair value measurements, employing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We have consistently used the same valuation techniques for all periods presented. Please read Note 1 - Organization, Basis of Presentation and Summary of Significant Accounting Policies - Fair Value Measurements and Note 7 - Fair Value Measurement in our Annual Report for further discussion.

We believe the carrying amount of cash and cash equivalents, restricted cash, 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 (as defined herein) 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 (as defined herein).

The recorded value of the 3.77% Senior Notes approximates its fair value as the notes were issued on September 30, 2016. The fair value of our fixed interest 3.77% Senior Notes will be classified as a Level 3 measurement as defined by ASC 820.

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 will recognize transfers between levels at the end of the reporting period in which the transfer occurred. There were no such transfers during the nine months ended September 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 unaudited condensed consolidated balance sheets, that were measured at fair value on a recurring basis as of September 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:					
September 30, 2016	$(309)	$—	$(309)	$—	$(309)
December 31, 2015	—	—	—	—	—
Interest rate swaps:					
September 30, 2016	$(1,121)	$—	$(1,121)	$—	$(1,121)
December 31, 2015	—	—	—	—	—

Table of Contents

The unamortized portion of the premium paid in relation to the weather derivative described in Note 5 - Derivatives is included within Risk management assets on our unaudited condensed consolidated balance sheets, however is not included as part of the above table as it is recorded at amortized carrying cost, not fair value.

Non Financial Assets and Liabilities

Non financial assets and liabilities that are measured at fair value on a nonrecurring basis are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of such assets and liabilities and their placement within the fair value hierarchy.

The fair values of asset retirement obligations are recurring and require significant Level 3 inputs. Please see a reconciliation of our asset retirement obligations and further discussion regarding the inputs in Note 11 - Asset Retirement Obligations. The fair values of certain property acquisitions and business combinations are nonrecurring and require significant Level 3 inputs. Please see further discussion in Note 2 - Acquisitions.

7. Property, Plant and Equipment, Net

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

	Useful Life (in years)	September 30, 2016	December 31, 2015
Land	N/A	$ 5,282	$ 5,282
Construction in progress	N/A	84,613	46,045
Buildings and improvements	4 to 40	10,623	9,864
Processing and treating plants	8 to 40	102,067	97,784
Pipelines and compressors	3 to 40	574,460	554,400
Storage	20 to 40	57,918	58,394
Equipment	5 to 20	38,591	22,207
Total property, plant and equipment		873,554	793,976
Accumulated depreciation		(173,576)	(145,963)
Property, plant and equipment, net		$ 699,978	$ 648,013

Of the gross property, plant and equipment balances at September 30, 2016 and December 31, 2015, $142.6 million and $111.9 million, respectively, were related to AlaTenn, Midla and High Point Gathering Systems, our FERC regulated interstate and intrastate assets.

Capitalized interest was $0.7 million and $0.9 million for the three months ended September 30, 2016 and 2015, respectively, and $1.7 million and $1.6 million for the nine months ended September 30, 2016 and 2015, respectively.

Depreciation expense was $9.5 million and $7.9 million for the three months ended September 30, 2016 and 2015, respectively, and $27.7 million and $23.3 million for the nine months ended September 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.

8. Goodwill and Intangible Assets, Net

The carrying value of goodwill as of September 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”).

Table of Contents

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):

	September 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	$(5,054)	$(3,124)
Dedicated acreage	(3,994)	(2,661)
	$(9,048)	$(5,785)
Net carrying amount:		
Customer relationships	$48,346	$50,276
Dedicated acreage	49,356	50,689
	$97,702	$100,965

Amortization expense related to our intangible assets totaled $1.1 million and $1.2 million for the three months ended September 30, 2016 and 2015, respectively, and $3.3 million and $4.3 million for the nine months ended September 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 nine months ended September 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	3,140	1,373	21,943	3,527	29,983
Contributions	—	—	—	13,099	13,099
Distributions	(11,350)	(2,092)	(42,113)	(7,242)	(62,797)
Balances at September 30, 2016	$114,620	$55,962	$46,228	$67,675	$284,485

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

20

Table of Contents

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

Balance Sheets:	September 30, 2016	December 31, 2015
Current assets	$ 143,362	$ 2,086
Non-current assets	1,388,584	288,617
Current liabilities	187,712	366
Non-current liabilities	489,667	23,617

	Three months ended September 30,		Nine months ended September 30,	
Statements of Operations:	2016	2015	2016	2015
Total revenue	$ 94,448	$ 9,201	$ 246,445	$ 13,610
Operating expense	10,443	1,274	17,984	3,011
Net income	66,410	5,975	187,187	6,216

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 September 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):

	September 30, 2016	December 31, 2015
Current portion of asset retirement obligation (1)	$ 6,106	$ 6,822
Accrued capital expenditures	8,151	3,984
Accrued expenses	10,638	3,178
Due to related parties	3,107	3,894
Accrued interest	5,228	1,411
Accrued property taxes	3,448	359
Accrued unitholder distribution (2)	5,000	—
Other	6,603	5,387
	$ 48,281	$ 25,035

(1) Associated with certain Gathering and Processing and Transmission assets.
(2) Please see Note 17 - Related Party Transactions for more information.

11. Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations (collectively, referred to as “AROs”) that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. Generally, the fair value of the liability is calculated using discounted cash flow techniques and based on internal estimates and assumptions related to (i) future retirement costs, (ii) future inflation rates and (iii) credit-adjusted risk-free interest rates. Significant increases or decreases in the assumptions would result in a significant change to the fair value measurement.

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 AROs include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets

Table of Contents

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, however, we do not believe that such demand will cease for the foreseeable future. The majority of the current portion of our AROs is related to the retirement of the Midla pipeline discussed in Note 16 - Commitments and Contingencies.

The following table is a reconciliation of our AROs for the nine months ended September 30, 2016 (in thousands):

Balances at December 31, 2015	$35,371
Liabilities assumed (1)	14,300
Expenditures	(771)
Accretion expense	1,082
Balances at September 30, 2016	$49,982
Less: current portion	6,106
Long-term asset retirement obligation	$43,876

(1) As a result of the Gulf of Mexico Pipeline acquisition described in Note 2 - Acquisitions, we recorded an 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 September 30, 2016 and December 31, 2015 and is presented in Other assets, net in our unaudited condensed consolidated balance sheets.

12. Debt Obligations

Our outstanding borrowings were as follows at the dates indicated (in thousands):

	September 30, 2016	December 31, 2015
Revolving credit facility	$ 672,694	$ 525,100
3.77% Senior Notes, due 2031	60,000	—
Other debt	—	2,338
Total debt obligations	732,694	527,438
Unamortized debt issuance costs (1)	(2,254)	—
	730,440	527,438
Less: Current portion, including unamortized debt issuance costs	1,351	2,338
Total debt obligation	$ 729,089	$ 525,100

(1) Relates to the 3.77% Senior Notes at September 30, 2016.

Credit Agreement

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 provided 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 (i) the Federal Funds Rate, plus 0.50%, (ii) 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 (iii) 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

Table of Contents

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.

On September 30, 2016, in connection with the 3.77% Senior Note Purchase Agreement, the Partnership entered into the Limited Waiver and Third Amendment to the Credit Agreement, which among other things, (i) allows Midla Holdings (as defined below), for so long as the 3.77% Senior Notes are outstanding, to be excluded from guaranteeing the obligations under the Credit Agreement and being subject to certain convents thereunder, (ii) releases the lien granted under the original credit agreement on D-Day's equity interests in FPS Equity, and (iii) deems the FPS Equity excluded property under the Credit Agreement. All other terms under the Credit Agreement remain the same.

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 September 30, 2016, our consolidated total leverage ratio was 4.43 and our interest coverage ratio was 7.18, which was in compliance with the related requirements.

For the nine months ended September 30, 2016 and 2015, the weighted average interest rate on borrowings under our Credit Agreement was approximately 4.27% and 3.50%, respectively.

At September 30, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $7.6 million and $1.8 million, respectively.

As of September 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.

3.77% Senior Notes

On September 30, 2016, Midla Financing, Midla, and MLGT entered into the 3.77% Senior Note Purchase Agreement. with certain institutional investors (the "Purchasers"). Pursuant to the 3.77% Senior Note Purchase Agreement, Midla Financing issued an aggregate of $60.0 million principal amount of Senior Notes to the Purchasers, which bear interest at a rate of 3.77% per annum that is paid quarterly. Principal on the 3.77% Senior Notes is payable in installments on the last business day of each fiscal quarter end beginning June 30, 2017. The 3.77% Senior Notes are payable in full on June 30, 2031. The average quarterly principal payment is approximately $1.1 million.The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million (after deducting related issuance costs). On September 30, 2016, we used $14.0 million of the proceeds to pay down a portion of our Credit Agreement. The 3.77% Senior Note Purchase Agreement allows the Partnership to reimburse itself for cash previously spent on the retirement of the former Midla pipeline and construction of the Midla-Natchez Line. As of September 30, 2016, we had restricted cash of $43.7 million from the issuance of the 3.77% Senior Notes.

The Note Purchase Agreement includes customary representations and warranties, affirmative and negative covenants (including financial covenants), and events of default that are customary for a transaction of this type. Many of these provisions apply not only to Midla Financing and the Note Guarantors, but also to American Midstream Midla Financing Holdings, LLC ("Midla Holdings"), a wholly owned subsidiary of the Partnership and the sole member of Midla Financing. Among other things, Midla Financing must maintain a debt service reserve account containing six months of principal and interest payments, and Midla Financing and the Note Guarantors (including any entities that become guarantors under the terms of the 3.77% Senior Note Purchase Agreement) are restricted from making distributions (a) until June 30, 2017, (b) unless the debt service coverage ratio is not less than, and is not projected for the following 12 calendar months to be less than, 1.20:1.00, and (c) unless certain other requirements are met.

In connection with the 3.77% Senior Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing's obligations under the 3.77% Senior Note Purchase Agreement. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible personal property, including the membership interests in each Note Guarantor held by Midla Financing, and Midla Holdings pledged the membership interests in Midla Financing to the Collateral Agent. Please read Note 16 - Commitments and Contingencies - Guarantees for further discussion.

Table of Contents

Net proceeds from the 3.77% Senior Notes are restricted and will be used (1) to fund project costs incurred in connection with (a) the construction of the Midla-Natchez Line, (b) the retirement of Midla's existing 1920's vintage pipeline, (c) the move of our Baton Rouge operations to the MLGT system, and (d) the reconfiguration of the DeSiard compression system and all related ancillary facilities, (2) to pay transaction fees and expenses in connection with the issuance of the 3.77% Senior Notes, and (3) for other general corporate purposes of Midla Financing. Please read Note 16 - Commitments and Contingencies - Regulatory matters for further discussion of the Midla-Natchez Line.

Other debt

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

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 September 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 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. During the second quarter of 2016, we sold 248,561 common units for proceeds of $3.0 million, net of commissions and accrued offering costs of $0.2 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. We sold no units during the third quarter of 2016. As of September 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 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.

Table of Contents

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 price 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.

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.

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.

Table of Contents

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $1.9 million from our General Partner as consideration for the issuance of 135,813 additional notional General Partner units for the nine months ended September 30, 2016. For the nine months ended September 30, 2015, we received proceeds of $2.0 million for the issuance of 143,517 additional notional General Partner units.

Outstanding Units

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

	September 30, 2016	December 31, 2015
Series A convertible preferred units	9,951	9,210
Series B convertible units	—	1,350
Series C convertible preferred units	8,664	—
Limited Partner common units	31,195	30,427
General Partner units	672	536

Distributions

We made cash distributions as follows (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Series A convertible preferred units	$2,449	$—	$2,449	$—
Series C convertible preferred units	1,302	—	1,302	—
Limited Partner common units	12,851	10,755	40,614	32,221
General Partner units	174	522	569	840
General Partners' incentive distribution rights	—	1,293	1,806	3,874
Total	$16,776	$12,570	$46,740	$36,935

On October 20, 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 September 30, 2016, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on November 14, 2016, to unitholders of record as of the close of business on November 3, 2016.

At September 30, 2016, we accrued $2.5 million of contractual cash distributions and $2.3 million of paid-in-kind Series A Units that will be issued in November 2016. At September 30, 2016, we accrued $1.8 million of contractual cash distributions and $1.8 million of Series C PIK Units that will be issued in November 2016.

For the nine months ended September 30, 2016, the Partnership issued 740,735 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 $11.4 million. For the nine months ended September 30, 2015, the Partnership issued 613,706 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 $12.6 million.

For the nine months ended September 30, 2016, the Partnership issued 93,039 of Series C PIK Units and accrued a combination of cash and paid-in-kind unitholder distributions for Series C Units with a fair value of $4.6 million.

The fair value of the paid-in-kind Series A Unit and Series 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 rate of 10.0%.

Table of Contents

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, and declared distributions on the Series B Units and General Partner units, including incentive distribution rights. Unvested unit-based payment awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted 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):

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Net income (loss) from continuing operations	$2,679	$(4,574)	$(4,876)	$(5,740)
Less: Net income attributable to noncontrolling interests	1,196	34	2,175	80
Net income (loss) from continuing operations attributable to the Partnership	1,483	(4,608)	(7,051)	(5,820)
Less:				
Distributions on Series A Units	4,806	4,991	13,878	12,598
Distributions on Series C Units	3,611	—	5,861	—
Declared distributions on Series B Units	—	324	—	1,157
General partner's distribution	174	1,815	2,375	4,714
General partner's share in undistributed loss	(265)	(294)	(928)	(737)
Net loss from continuing operations available to Limited Partners	(6,843)	(11,444)	(28,237)	(23,552)
Net loss from discontinued operations available to Limited Partners	—	(53)	—	(79)
Net loss available to Limited Partners	$(6,843)	$(11,497)	$(28,237)	$(23,631)
Weighted average number of common units used in computation of Limited Partners' net loss per common unit - basic and diluted	31,168	23,987	30,979	23,154
Limited Partners' net loss per common unit - basic and diluted (1)	$(0.22)	$(0.48)	$(0.91)	$(1.02)

(1) Potential common unit equivalents are antidilutive for all periods and, as a result, have been excluded from the determination of diluted limited partners' net income (loss) per common unit

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 September 30, 2016 and December 31, 2015, there were 4,951,795 and 15,484 common units, 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.

Table of Contents

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 contain 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.

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

	Units	Weighted-Average Grant Price
Outstanding at beginning of period	569,759	$ 13.15
Granted	1,342,016	1.89
Forfeited	(313,884)	2.22
Vested	(243,828)	12.97
Outstanding at end of period	1,354,063	$ 4.55

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. For the three months ended September 30, 2016 and 2015, compensation costs related to these awards were $1.4 million and $0.6 million, respectively, and for the nine months ended September 30, 2016 and 2015, were $2.9 million and $2.8 million, respectively. For the three and nine months ended September 30, 2016, $0.7 million and $2.2 million, respectively, were classified as equity compensation expense. For both the three and nine months ended September 30, 2016, the remaining $0.7 million related to the acceleration of equity awards for certain employees was classified as transaction costs within Selling, general, and administrative expense in our unaudited condensed consolidated statements of operations. Please see the Note 16 - Commitments and Contingencies for further discussion. The entire balance for the three and nine months ended September 30, 2015 was classified as Equity compensation expense.

The total fair value of vested units at the time of vesting was $1.8 million and $2.5 million for the nine months ended September 30, 2016 and 2015, respectively.

Equity compensation expense related to unvested awards not yet recognized at September 30, 2016 and 2015 was $4.9 million and $5.5 million, respectively, and the weighted average period over which this cost is expected to be recognized as of September 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 unit awards at the time of grant. Prior to the third quarter of 2016, these awards were accounted for as liability classified awards and equity-based compensation was accrued from the service-inception date through the estimated date of meeting both the performance and service conditions. During the third quarter of 2016, we decided to settle the obligation in cash. We reclassified previously recognized equity based compensation expense of $0.6 million from equity compensation expense to direct operating

expenses in our condensed consolidated statement of operations. Expense related to these awards for the three and nine months ended September 30, 2016 was $0.6 million and $1.2 million, respectively. Compensation costs related to unvested awards not yet recognized at September 30, 2016 was $0.3 million.

Option to Purchase Common Units. In December 2015, the Board of Directors of our General Partner approved the grant of an option to purchase 200,000 common units of the Partnership at an exercise price per unit equal to $7.50 (the “December Option Grant”). The December 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.

In August 2016, the Board of Directors of our General Partner approved the grant of an option to purchase 30,000 common units of the Partnership at an exercise price per unit equal to $12.00 (the “August Option Grant”). The August Option Grant will vest in one lump sum installment on July 31, 2019, subject to continued employment with the Company, and will expire on July 31st of the calendar year following the calendar year in which it vests.

Table of Contents

In September 2016, the Board of Directors of our General Partner approved the grant of an option to purchase 45,000 common units of the Partnership at an exercise price per unit equal to $13.88. On the one year grant anniversary date 25% of the option grant will vest, and the remaining 75% will vest in 25% increments on each succeeding anniversary date. The option grants will expire September 30th of the calendar year following the calendar year in which it vests.

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

	Nine months ended September 30, 2016	
	Units	Weighted-Average Exercise Price
Outstanding at beginning of period	200,000	$ 7.50
Granted	75,000	13.13
Forfeited	—	—
Vested	—	—
Outstanding at end of period	275,000	$ 9.03

Compensation costs related to these awards for the three and nine months ended September 30, 2016 were immaterial. Compensation costs related to unvested awards not yet recognized at September 30, 2016 was $0.2 million.

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 nine months ended September 30, 2016 was $0.4 million and $1.3 million, respectively, resulting in an effective tax rate of 14.1% and 36.4%, respectively. For the three and nine months ended September 30, 2015, income tax expense was $0.6 million and $1.1 million, respectively, resulting in an effective tax rate of 14.9% and 22.8%, respectively.

The effective tax rates for the three and nine months ended September 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 their operation, 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.

Table of Contents

On April 16, 2015, FERC approved the stipulation and agreement (the "Midla Agreement") allowing Midla to retire the existing 1920's vintage pipeline and replace it with 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 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 the first six months of 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 to a corporate relocation plan and communicated that plan to the impacted employees. 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 were recognized ratably over the requisite service period and presented in Selling, general and administrative expenses in our unaudited condensed consolidated statement of operations. For the three and nine months ended September 30, 2016, we recorded $5.3 million and $6.6 million, respectively, in termination benefits. At September 30, 2016, our outstanding accrual was approximately $0.8 million and is recorded in Accrued expenses and other current liabilities in our unaudited condensed consolidated balance sheet. We expect the plan to be complete in the fourth quarter of 2016.

On August 31, 2016, we vacated our former corporate office space and recorded a $0.4 million liability for the present value of the remaining lease payments. We also entered into a new corporate office lease which commenced on August 1, 2016 and expires on August 15, 2032. Below is our contractual obligation related to the new corporate office lease (in thousands):

	Office Lease
2016	$—
2017	369
2018	895
2019	920
2020	945
Thereafter	12,844
	$15,973

17. Related Party Transactions

In December 2013, the Partnership completed a merger with Blackwater Midstream Holdings, LLC ("Blackwater") and AL Blackwater, LLC ("ALB"), both affiliates of ArcLight, under which Blackwater became a wholly owned subsidiary of the Partnership. The merger was accounted for as a common control transaction.The merger agreement included a provision whereby ALB would be entitled to additional $5.0 million of merger consideration based on Blackwater's assets meeting certain operating targets. During the third quarter of 2016, the Partnership determined that it was probable the operating targets would be met in early 2017 and recorded a $5.0 million accrued unitholder distribution in the accompanying condensed consolidated financial statements as of September 30, 2016.

Employees of our General Partner are assigned to work for the Partnership or other affiliates of our General Partner. Where directly attributable, all compensation and related 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 on the expenses charged to us. During the three and nine months

ended September 30, 2016, expenses of $11.6 million and $28.5 million, respectively, were charged to the Partnership by our General Partner. During the three and nine months ended September 30, 2015, expenses of $7.2 million and $21.4 million, respectively, were charged to the Partnership by our General Partner.

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 nine months ended September 30, 2016, the Partnership recognized $0.2 million and $0.6 million, respectively, in management fee income, and recognized $0.3 million and $1.2 million, respectively, for the three and nine months ended September 30, 2015 that was recorded as a reduction to Selling, general and administrative expenses.

Table of Contents

As of September 30, 2016 and December 31, 2015, the Partnership had $3.1 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.

Table of Contents

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

	Three months ended September 30, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$43,163	$ 14,368	$ 6,140	$63,671
Gain (loss) on commodity derivatives, net	148	(1)	—	147
Total revenue	43,311	14,367	6,140	63,818
Operating expenses:				
Purchases of natural gas, NGLs and condensate	23,794	2,288	—	26,082
Direct operating expenses	9,924	2,915	3,203	16,042
Selling, general and administrative expenses				13,289
Equity compensation expense				104
Depreciation, amortization and accretion expense				11,018
Total operating expenses				66,535
Interest expense				(5,156)
Earnings in unconsolidated affiliates				10,993
Income tax expense				(441)
Net income				2,679
Less: Net income attributable to noncontrolling interests				1,196
Net income attributable to the Partnership				$1,483
Segment gross margin (1)	$18,821	$ 12,071	$ 2,937	$33,829

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized gain on commodity derivatives of $0.3 million, (ii) construction and operating management agreement ("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 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.

Table of Contents

	Three months ended September 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$40,103	$ 9,977	$ 4,745	$54,825
Gain on commodity derivatives, net	816	—	—	816
Total revenue	40,919	9,977	4,745	55,641
Operating expenses:				
Purchases of natural gas, NGLs and condensate	22,055	2,376	—	24,431
Direct operating expenses	10,119	3,595	1,614	15,328
Selling, general and administrative expenses				7,639
Equity compensation expense				574
Depreciation, amortization and accretion expense				9,160
Total operating expenses				57,132
Loss on sale of assets, net				(32)
Interest expense				(3,553)
Earnings in unconsolidated affiliate				1,094
Income tax expense				(592)
Loss from discontinued operations, net of tax				(53)
Net loss				(4,627)
Less: Net income attributable to noncontrolling interests				34
Net loss attributable to the Partnership				$(4,661)
Segment gross margin (1)	$18,422	$ 7,581	$ 3,131	$29,134

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized gain on commodity derivatives of $0.2 million, (ii) COMA income of $0.2 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 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.

Table of Contents

	Nine months ended September 30, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$116,091	$ 33,335	$ 16,516	$165,942
Loss on commodity derivatives, net	(719)	(3)	—	(722)
Total revenue	115,372	33,332	16,516	165,220
Operating expenses:				
Purchases of natural gas, NGLs and condensate	60,206	4,890	—	65,096
Direct operating expenses	31,158	9,181	6,415	46,754
Selling, general and administrative expenses				33,255
Equity compensation expense				2,213
Depreciation, amortization and accretion expense				32,015
Total operating expenses				179,333
Gain on sale of assets, net				90
Interest expense				(19,535)
Earnings in unconsolidated affiliates				29,983
Income tax expense				(1,301)
Net loss				(4,876)
Less: Net income attributable to noncontrolling interests				2,175
Net loss attributable to the Partnership				$(7,051)
Segment gross margin (1)	$55,157	$ 28,419	$ 10,101	$93,677

(1)Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized loss on commodity derivatives of $(0.3) million, (ii) COMA income of $0.3 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 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.

Table of Contents

	Nine months ended September 30, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	$138,991	$ 34,148	$ 13,346	$186,485
Gain on commodity derivatives, net	1,274	—	—	1,274
Total revenue	140,265	34,148	13,346	187,759
Operating expenses:				
Purchases of natural gas, NGLs and condensate	79,645	7,097	—	86,742
Direct operating expenses	28,342	10,027	4,793	43,162
Selling, general and administrative expenses				20,145
Equity compensation expense				2,822
Depreciation, amortization and accretion expense				28,099
Total operating expenses				180,970
Loss on sale of assets, net				(3,010)
Interest expense				(9,719)
Earnings in unconsolidated affiliates				1,265
Income tax expense				(1,065)
Loss from discontinued operations, net of tax				(79)
Net loss				(5,819)
Less: Net income attributable to noncontrolling interests				80
Net loss attributable to the Partnership				$(5,899)
Segment gross margin (1)	$59,687	$ 26,975	$ 8,553	$95,215

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less (i) unrealized gain on commodity derivatives of $0.3 million, (ii) COMA income of $0.6 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:

	September 30, 2016	December 31, 2015
Segment assets:		
Gathering and Processing	$593,610	$572,824
Transmission	208,370	133,870
Terminals	97,201	84,449
Other (1)	299,946	100,153
Total assets	$1,199,127	$891,296

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

35

Table of Contents

19. Subsequent Events

Distribution

On October 20, 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 September 30, 2016, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on November 14, 2016, to unitholders of record as of the close of business on November 3, 2016.

Interest Rate Swap

On October 20, 2016, we entered into an interest rate swap with a notional amount of $150 million at a fixed rate of 1.475%. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap is effective beginning January 1, 2018 and will expire December 31, 2022.

JP Energy Partners Merger

On October 23, 2016, the Partnership and our General Partner entered into an Agreement and Plan of Merger (the “LP Merger Agreement”) with JP Energy Partners LP, a Delaware limited partnership (“JPE”), JPE Energy GP II LLC, a Delaware limited liability company and the general partner of JPE (“JPE GP”), Argo Merger Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of the Partnership (“AMID Merger Sub”), and Argo Merger GP Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of the Partnership (“GP Sub”). Upon the terms and subject to the conditions set forth in the LP Merger Agreement, JPE will merge with and into AMID Merger Sub (the “LP Merger”), with JPE continuing its existence under Delaware law as the surviving entity in the LP Merger and an indirect but economically wholly-owned subsidiary of the Partnership. The conflicts committee and the Board of Directors of our General Partner unanimously approved the LP Merger Agreement. The conflicts committee retained independent financial and legal advisors. The board of directors of JPE GP unanimously approved the LP Merger Agreement and agreed to submit the LP Merger Agreement to a vote of JPE unitholders and to recommend that JPE’s unitholders adopt the LP Merger Agreement.

At the effective time of the LP Merger (the “Effective Time”), (i) each common unit of JPE (each, a “JPE Common Unit”) and each subordinated unit of JPE (each, a “JPE Subordinated Unit”) issued and outstanding or deemed issued and outstanding as of immediately prior to the Effective Time (other than JPE Common Units and JPE Subordinated Units held by Lonestar Midstream Holdings, LLC, a Delaware limited liability company, JP Energy Development LP, a Delaware limited partnership, or their respective affiliates (together the “Affiliated Holders”)) will be converted into the right to receive 0.5775 (the “Exchange Ratio”) of a common unit representing limited partner interests in the Partnership (the “Public Unit Consideration”) and (ii) each JPE Common Unit and each JPE Subordinated Unit issued and outstanding or deemed issued and outstanding as of immediately prior to the Effective Time held by the Affiliated Holders will be converted into the right to receive 0.5225 of a common unit (the “Affiliate Unit Consideration” and, together with the Public Unit Consideration, the “LP Merger Consideration”).

In connection with the LP Merger Agreement, on October 23, 2016, our General Partner entered into an Agreement and Plan of Merger (the “GP Merger Agreement”) with JPE GP and Argo GP Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of our General Partner. Upon the terms and subject to the conditions set forth in the GP Merger Agreement, Argo GP Sub, LLC will merge with and into JPE GP (the “GP Merger”), with the separate limited liability company existence of Argo GP Sub, LLC ceasing to exist and JPE GP continuing its existence under Delaware law as the surviving entity in the GP Merger and a wholly owned subsidiary of our General Partner. In connection with the consummation of the GP Merger, GP Sub will be admitted as the sole general partner of JPE and

JPE GP will simultaneously cease to be the general partner of JPE. Under the terms of the GP Merger Agreement, all of the JPE GP membership interests issued and outstanding immediately prior to the effective time of the GP Merger will convert into a right to receive Class A Membership Interests (as such term is defined in the Third Amended and Restated Limited Liability Company of American Midstream GP, LLC, dated as of May 2, 2016 (the "AMID GP LLC Agreement")) in our General Partner, representing a Sharing Percentage (as such term is defined in the AMID GP LLC Agreement) of 18.786%. Concurrently with the effective time of the GP Merger, the AMID GP LLC Agreement will be amended to reflect the issuance of such Class A Membership Interests.

Additional Delta House Investment

On October 31, 2016, D-Day acquired an additional 6.2% non-operated direct interest in Delta House for a purchase price of approximately $48.8 million which was funded with $34.5 million in net proceeds from the issuance of 2,333,333 newly issued Series D convertible preferred units ("Series D Preferred Units) plus $14.3 million of additional borrowings under our Credit

Table of Contents

Agreement. The Series D Preferred Units were issued at $15.00 per unit and if any Series D Preferred Units remain outstanding on June 30, 2017, the Partnership will issue a warrant to purchase up to 700,000 common units at an exercise price of $22.00 per common unit. An affiliate of our General Partner holds the Series D Preferred Units and participates in the related distributions which are to be made in paid-in-kind Series D Units, cash or a combination thereof at the election of the Board of Directors of our General Partner.

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 20.1% non-operated indirect and direct interest in Delta House.

Table of Contents

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 production 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 revenues and the financial viability 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 complete and integrate our current and future acquisitions (including the merger with JP Energy), 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

Table of Contents

- 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 1,100 Bcf/d of natural gas and operate approximately 2.4 million barrels of storage capacity across three marine terminal sites.

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

- Net income (loss) attributable to the Partnership increased to $1.5 million, primarily due to higher total revenues and earnings from unconsolidated affiliates, which was partially offset by an increase in operating expenses;

- We completed the issuance by Midla Financing of $60.0 million in aggregate principal amount of senior secured notes due June 30, 2031 that bear interest at a rate of 3.77% per annum (the “3.77% Senior Notes”). The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million (after deducting related issuance costs);

- We vacated our previous corporate office space and recorded a $0.4 million liability equal to the present value of the remaining lease payments. We also entered into a new corporate office lease which commenced on August 1, 2016 and expires on August 15, 2032, with total contractual lease payments of $16.0 million;

- Earnings in unconsolidated affiliates was $11.0 million, an increase $9.9 million, as compared to the same period in 2015 primarily due to incremental earnings related to our investment in Delta House and the interests in the entities underlying the Emerald Transactions;

- Gross margin amounted to $33.8 million, or an increase of $4.7 million, as compared to the same period in 2015 primarily due to higher firm and interruptible transportation throughput volumes associated with our Transmission segment;

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Adjusted EBITDA increased to $35.8 million, or an increase of 126.1%, 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 $12.9 million to our common unitholders, or $0.4125 per common unit.

Operational highlights for the three months ended September 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 89.7% as compared to 80.7% for the same period in 2015;

- Contracted capacity for our Terminals segment averaged 2,224,067 Bbls, representing a 40.1% increase compared to the same period in 2015;

Table of Contents

- Average condensate production totaled 91.7 Mgal/d, representing a 3.5 Mgal/d increase compared to the same period in 2015;

- Average gross NGL production totaled 145.1 Mgal/d, representing a 58.0 Mgal/d decrease compared to the same period in 2015; and

- Throughput volumes attributable to the Partnership totaled 1,084.6 MMcf/d, representing a 58.7 MMcf/d increase compared to the same period in 2015.

Recent Developments

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

3.77% Senior Notes

On September 30, 2016, American Midstream Midla Financing, LLC (“Midla Financing”), American Midstream (Midla), LLC (“Midla”) and Mid Louisiana Gas Transmission LLC (“MLGT” and, together with Midla, the “Note Guarantors”), each an indirect subsidiary of the Partnership, entered into a Note Purchase and Guaranty Agreement (the “3.77% Senior Note Purchase Agreement”) with certain institutional investors (the “Purchasers”). Pursuant to the 3.77% Senior Note Purchase Agreement, Midla Financing sold $60.0 million in aggregate principal amount of Senior Notes to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly. Principal on the 3.77% Senior Notes will be paid on the last business day of each fiscal quarter end starting June 30, 2017. The 3.77% Senior Notes are payable in full on June 30, 2031. The average quarterly principal payment is approximately $1.1 million. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million (after deducting related issuance costs). The net proceeds are restricted and will partially be used to fund the retirement of Midla’s existing 1920’s vintage pipeline and the construction of a new replacement pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the “Midla-Natchez Line”). We have included these net proceeds in Restricted cash in our unaudited condensed consolidated balance sheet. Construction commenced on the Midla-Natchez Line in the second quarter of 2016 with service expected to begin within the first six months of 2017.

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 $224.6 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 Pipeline.

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.

Accrued unitholder distribution

In December 2013, the Partnership completed a merger with Blackwater Midstream Holdings, LLC (“Blackwater”) and AL Blackwater, LLC (“ALB”), both affiliates of ArcLight, under which Blackwater became a wholly owned subsidiary of the Partnership. The merger was accounted for as a common control transaction. The merger agreement included a provision whereby ALB would be entitled to additional $5.0 million of merger consideration based on Blackwater’s assets meeting certain operating targets. During the third quarter of 2016, the Partnership determined that it was probable the operating targets would be met in early 2017 and recorded a $5.0 million accrued unitholder distribution in the accompanying condensed consolidated financial statements as of September 30, 2016.

Table of Contents

Commodity Prices

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $51.60 per barrel to a low of $26.21 per barrel from January 1, 2016 through November 3, 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.25 per MMBtu to a low of $1.49 per MMBtu from January 1, 2016 through November 3, 2016. During 2016, we entered into commodity contracts with existing counterparties and economically hedged approximately 34% of our expected exposure to NGL prices and 51% of our expected exposure to oil prices through the end of 2016.

Fluctuations in energy prices can 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 were in 2015 and thus far in 2016, 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 September 30, 2016, our Gathering and Processing segment and our Transmission segment derived 15% and 12% of their respective revenue from ConocoPhillips Company.

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 October 20, 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 September 30, 2016, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on November 14, 2016, to unitholders of record as of the close of business on November 3, 2016.

Interest Rate Swap

On October 20, 2016, we entered into an interest rate swap with a notional amount of $150 million at a fixed rate of 1.475%. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap is effective beginning January 1, 2018 and will expire December 31, 2022.

JP Energy Partners Merger

On October 23, 2016, the Partnership and our General Partner entered into an Agreement and Plan of Merger (the “LP Merger Agreement”) with JP Energy Partners LP, a Delaware limited partnership (“JPE”), JPE Energy GP II LLC, a Delaware limited liability company and the general partner of JPE (“JPE GP”), Argo Merger Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of the Partnership (“AMID Merger Sub”), and Argo Merger GP Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of the Partnership (“GP Sub”). Upon the terms and subject to the conditions set forth in the LP Merger Agreement, JPE will merge with and into AMID Merger Sub (the “LP Merger”), with JPE continuing its existence under Delaware law as the surviving entity in the LP Merger and an indirect but economically wholly-owned subsidiary of the Partnership. The conflicts committee and the board of directors of our General Partner unanimously approved the LP Merger Agreement. The conflicts committee retained independent financial and legal advisors. The board of directors of JPE GP unanimously approved the LP Merger Agreement and agreed to submit the LP Merger Agreement to a vote of JPE unitholders and to recommend that JPE’s unitholders adopt the LP Merger Agreement.

Table of Contents

At the effective time of the LP Merger (the "Effective Time"), (i) each common unit of JPE (each, a "JPE Common Unit") and each subordinated unit of JPE (each, a "JPE Subordinated Unit") issued and outstanding or deemed issued and outstanding as of immediately prior to the Effective Time (other than JPE Common Units and JPE Subordinated Units held by Lonestar Midstream Holdings, LLC, a Delaware limited liability company, JP Energy Development LP, a Delaware limited partnership, or their respective affiliates (together the "Affiliated Holders")) will be converted into the right to receive 0.5775 (the "Exchange Ratio") of a common unit representing limited partner interests in the Partnership (the "Public Unit Consideration") and (ii) each JPE Common Unit and each JPE Subordinated Unit issued and outstanding or deemed issued and outstanding as of immediately prior to the Effective Time held by the Affiliated Holders will be converted into the right to receive 0.5225 of a partnership common unit (the "Affiliate Unit Consideration" and, together with the Public Unit Consideration, the "LP Merger Consideration").

In connection with the LP Merger Agreement, on October 23, 2016, our General Partner entered into an Agreement and Plan of Merger (the "GP Merger Agreement") with JPE GP and Argo GP Sub, LLC, a Delaware limited liability company and wholly owned subsidiary of our General Partner. Upon the terms and subject to the conditions set forth in the GP Merger Agreement, Argo GP Sub, LLC will merge with and into JPE GP (the "GP Merger"), with the separate limited liability company existence of Argo GP Sub, LLC ceasing to exist and JPE GP continuing its existence under Delaware law as the surviving entity in the GP Merger and a wholly owned subsidiary of our General Partner. In connection with the consummation of the GP Merger, GP Sub will be admitted as the sole general partner of JPE and JPE GP will simultaneously cease to be the general partner of JPE. Under the terms of the GP Merger Agreement, all of the JPE GP membership interests issued and outstanding immediately prior to the effective time of the GP Merger will convert into a right to receive Class A Membership Interests (as such term is defined in the Third Amended and Restated Limited Liability Company of American Midstream GP, LLC, dated as of May 2, 2016 (the "AMID GP LLC Agreement")) in our General Partner, representing a Sharing Percentage (as such term is defined in the AMID GP LLC Agreement) of 18.786%. Concurrently with the effective time of the GP Merger, the AMID GP LLC Agreement will be amended to reflect the issuance of such Class A Membership Interests.

Additional Delta House Investment

On October 31, 2016, D-Day acquired an additional 6.2% non-operated direct interest in Delta House for a purchase price of approximately $48.8 million which was funded with $34.5 million in proceeds from the issuance of 2,333,333 newly issued Series D convertible preferred units ("Series D Preferred Units) plus $14.3 million of additional borrowings under our Credit Agreement. The Series D Preferred Units were issued at $15.00 per unit and if any Series D Preferred Units remain outstanding on June 30, 2017, the Partnership will issue a warrant to purchase up to 700,000 common units at an exercise price of $22.00 per common unit. An affiliate of our General Partner holds the Series D Preferred Units and participates in the related distributions which are to be made in paid-in-kind Series D Units, cash or a combination thereof at the election of the Board of Directors of our General Partner.

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 owning a combined 20.1% non-operated indirect and direct interests in Delta House.

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.

Table of Contents

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 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.

Table of Contents

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 September 30, 2016 and 2015, $30.3 million and $23.5 million, or 89.7% and 80.7%, 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 September 30, 2016 and 2015 (in thousands):

	For the Three Months Ended September 30, 2016		For the Three Months Ended September 30, 2015	
	Segment Gross Margin	Percent of Segment Gross Margin	Segment Gross Margin	Percent of Segment Gross Margin
Gathering and Processing				
Fee-based	$13,306	70.7 %	$8,658	47.0 %
Fixed margin	2,033	10.8 %	4,145	22.5 %
Percent-of-proceeds	3,482	18.5 %	5,619	30.5 %
Total	$18,821	100.0 %	$18,422	100.0 %
Transmission				
Firm transportation	$4,985	41.3 %	$2,722	35.9 %
Interruptible transportation	7,086	58.7 %	4,859	64.1 %
Total	$12,071	100.0 %	$7,581	100.0 %
Terminals				
Firm storage	$2,937	100.0 %	$3,131	100.0 %
Total	$2,937	100.0 %	$3,131	100.0 %

Table of Contents

For the nine months ended September 30, 2016 and 2015, $83.8 million and $79.6 million, or 89.4% and 83.6%, 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 nine months ended September 30, 2016 and 2015 (in thousands):

	For the Nine Months Ended September 30, 2016		For the Nine Months Ended September 30, 2015	
	Segment Gross Margin	Percent of Segment Gross Margin	Segment Gross Margin	Percent of Segment Gross Margin
Gathering and Processing				
Fee-based	$38,334	69.5 %	$28,053	47.0 %
Fixed margin	6,950	12.6 %	16,056	26.9 %
Percent-of-proceeds	9,873	17.9 %	15,578	26.1 %
Total	$55,157	100.0 %	$59,687	100.0 %
Transmission				
Firm transportation	$11,879	41.8 %	$9,711	36.0 %
Interruptible transportation	16,540	58.2 %	17,264	64.0 %
Total	$28,419	100.0 %	$26,975	100.0 %
Terminals				
Firm storage	$10,101	100.0 %	$8,553	100.0 %
Total	$10,101	100.0 %	$8,553	100.0 %

Cash distributions derived from our unconsolidated affiliates amounted to $22.7 million and $5.1 million for the three months ended September 30, 2016 and 2015, respectively, and $62.8 million and $6.6 million for the nine months ended September 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, operating margin and direct operating expenses on a segment basis, and Adjusted EBITDA on a company-wide basis.

Throughput Volumes

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

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines.

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

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

Table of Contents

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 less unrealized gains 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 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 total revenue 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. For a reconciliation of gross margin to Net income (loss), please read "- Non-GAAP Financial Measures."

Operating Margin

Operating margin is a supplemental non-GAAP financial 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. For a reconciliation of Operating Margin to net income (loss), please read "- Non-GAAP Financial Measures."

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 supplemental non-GAAP financial 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.

Table of Contents

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, distributions from unconsolidated affiliates, transaction expenses and selected charges that are unusual or nonrecurring, less COMA income, OPEB plan net periodic benefit, earnings in unconsolidated affiliates, 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. For a reconciliation of Adjusted EBITDA to net income (loss), please read "- Non-GAAP Financial Measures."

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.

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 nine months ended September 30, 2016 and 2015 (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Reconciliation of Total Gross Margin to Net income (loss) attributable to the Partnership:				
Gathering and Processing segment gross margin	$18,821	$18,422	$55,157	$59,687
Transmission segment gross margin	12,071	7,581	28,419	26,975
Terminals segment gross margin (1)	2,937	3,131	10,101	8,553
Total Gross Margin	33,829	29,134	93,677	95,215
Less:				
Direct operating expenses (1)	12,839	13,714	40,339	38,369
Total Operating Margin	20,990	15,420	53,338	56,846
Plus:				
Gain (loss) on commodity derivatives, net	147	816	(722)	1,274
Earnings in unconsolidated affiliates	10,993	1,094	29,983	1,265
Less:				
Selling, general and administrative expenses	13,289	7,639	33,255	20,145
Equity compensation expense	104	574	2,213	2,822
Depreciation, amortization and accretion expense	11,018	9,160	32,015	28,099
(Gain) loss on sale of assets, net	—	32	(90)	3,010
Interest expense	5,156	3,553	19,535	9,719
Other, net (2)	(557)	354	(754)	265

Income tax expense	441	592	1,301	1,065
Loss from discontinued operations, net of tax	—	53	—	79
Net loss attributable to noncontrolling interest	1,196	34	2,175	80
Net income (loss) attributable to the Partnership	$1,483	$(4,661)	$(7,051)	$(5,899)

(1) Direct operating expenses include Gathering and Processing segment direct operating expenses of $9.9 million and $10.1 million, respectively, and Transmission segment direct operating expenses of $2.9 million and $3.6 million, respectively, for

Table of Contents

the three months ended September 30, 2016 and 2015. Direct operating expenses related to our Terminals segment of $3.2 million and $1.6 million for the three months ended September 30, 2016 and 2015, respectively, are included within the calculation of Terminals segment gross margin.

Direct operating expenses include Gathering and Processing segment direct operating expenses of $31.2 million and $28.3 million, respectively, and Transmission segment direct operating expenses of $9.2 million and $10.0 million, respectively, for the nine months ended September 30, 2016 and 2015. Direct operating expenses related to our Terminals segment of $6.4 million and $4.8 million, respectively, for the nine months ended September 30, 2016 and 2015 are included within the calculation of Terminals segment gross margin.

(2) Other, net includes realized gain (loss) on commodity derivatives of $(0.2) million and $0.6 million, respectively, and COMA income of $0.4 million and $0.2 million, respectively, for the three months ended September 30, 2016 and 2015.

Other, net includes realized gain (loss) on commodity derivatives of $(0.4) million and $1.0 million, respectively, and COMA income of $0.3 million and $0.7 million, respectively, for the nine months ended September 30, 2016 and 2015, respectively.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Reconciliation of Net income (loss) attributable to the Partnership to Adjusted EBITDA:				
Net income (loss) attributable to the Partnership	$1,483	$(4,661)	$(7,051)	$(5,899)
Add:				
Depreciation, amortization and accretion expense	10,747	9,160	31,531	28,099
Interest expense	6,225	3,285	16,854	9,029
Debt issuance costs paid	2,512	1,708	3,987	1,984
Unrealized (gain) loss on derivatives, net	(1,958)	(311)	1,430	(523)
Non-cash equity compensation expense	104	643	2,213	2,891
Transaction expenses (1)	4,899	1,325	9,557	1,368
Income tax expense	441	419	1,301	876
Distributions from unconsolidated affiliates	22,720	5,068	62,797	6,568
General Partner contribution for cost reimbursement	—	330	—	330
Deduct:				
Earnings in unconsolidated affiliates	10,993	1,094	29,983	1,265
COMA income	388	221	341	702
OPEB plan net periodic benefit	5	3	13	9
Gain (loss) on sale of assets, net	—	(182)	90	(3,160)
Adjusted EBITDA	$35,787	$15,830	$92,192	$45,907

(1) Transaction expenses for the three and nine months ended September 30, 2016 included office relocation expenses of $4.6 million and $9.0 million, respectively.

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.”

Table of Contents

Results of Operations — Combined Overview

Net loss attributable to the Partnership decreased by $6.2 million for the three months ended September 30, 2016, and increased by $1.2 million, for the nine months ended September 30, 2016 as compared to the same periods in 2015. For the three months ended September 30, 2016, direct operating expenses increased by $0.7 million primarily due to recognizing $1.2 million of expense associated with liability classified awards granted to certain employees. The increase due to the liability classified awards is partially offset by lower compressor rental expense of $0.5 million. Selling, general and administrative expense increased by $5.7 million primarily due to incremental transaction costs and corporate relocation expenses of $4.8 million. Interest expense increased by $1.6 million as a result of additional borrowings to fund capital growth and acquisitions. Earnings from unconsolidated affiliates increased by $9.9 million as result our investment in Delta House and Emerald transactions.

For the nine months ended September 30, 2016, direct operating expenses increased by $3.6 million due to certain integrity management programs, environmental regulations and liability classified awards of $1.2 million. Selling, general and administrative expenses increased by $13.1 million largely due to incremental transaction costs and corporate relocation expenses of $9.6 million, interest expense increased by $9.8 million as a result of additional borrowings to fund capital growth and acquisitions. Earnings from unconsolidated affiliates increased by $28.7 million as a result of our investment in the Delta House and Emerald transactions.

Gross margin increased by $4.7 million ,or 16.1%, for the three months ended September 30, 2016, and decreased by $1.5 million, or 1.6%, for the nine months ended September 30, 2016 as compared to the same periods in 2015. For the three months ended September 30, 2016, gross margin increased due to higher average throughput volumes associated with our Transmission segment amounting to $4.5 million and an increase of $0.4 million in our Gathering and Processing segment gross margin, partially offset by a decrease of $0.2 million related to our Terminals segment as a result of liability classified awards. For the nine months ended September 30, 2016, the $1.5 million decrease in gross margin was primarily a result of a decline in our Gathering and Processing segment gross margins of $4.5 million as a result of lower NGL and condensate production, which was partially offset by an increase in our Terminals segment gross margins of $1.5 million due to an increase in firm storage contracted capacity offset by expenses related to liability classified awards and higher Transmission segment gross margins of $1.4 million.

For the three months ended September 30, 2016, Adjusted EBITDA increased $20.0 million, or 126.1%, compared to the same period in 2015. The increase is primarily related to higher distributions from our unconsolidated affiliates of $17.7 million largely due to our investments in Delta House and the entities underlying the Emerald Transactions. For the nine months ended September 30, 2016, Adjusted EBITDA increased $46.3 million, or 100.8%, compared to the same period in 2015. The increase is primarily related to higher distributions from our unconsolidated affiliates of $56.2 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 $7.8 million and an increase in transaction expenses of $8.2 million related to corporate relocation expenses.

We distributed $12.9 million to holders of our common units, or $0.4125 per common unit, during the three months ended September 30, 2016, and $40.6 million, or $1.2975 per common unit, during the nine months ended September 30, 2016.

Table of Contents

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 September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Statement of Operations Data:				
Revenue	$63,671	$54,825	$165,942	$186,485
Gain (loss) on commodity derivatives, net	147	816	(722)	1,274
Total revenue	63,818	55,641	165,220	187,759
Operating expenses:				
Purchases of natural gas, NGLs and condensate	26,082	24,431	65,096	86,742
Direct operating expenses	16,042	15,328	46,754	43,162
Selling, general and administrative expenses	13,289	7,639	33,255	20,145
Equity compensation expense (1)	104	574	2,213	2,822
Depreciation, amortization and accretion expense	11,018	9,160	32,015	28,099
Total operating expenses	66,535	57,132	179,333	180,970
Gain (loss) on sale of assets, net	—	(32)	90	(3,010)
Operating income (loss)	(2,717)	(1,523)	(14,023)	3,779
Other income (expense):				
Interest expense	(5,156)	(3,553)	(19,535)	(9,719)
Earnings in unconsolidated affiliates	10,993	1,094	29,983	1,265
Income (loss) from continuing operations before taxes	3,120	(3,982)	(3,575)	(4,675)
Income tax expense	(441)	(592)	(1,301)	(1,065)
Income (loss) from continuing operations	2,679	(4,574)	(4,876)	(5,740)
Loss from discontinued operations, net of tax	—	(53)	—	(79)
Net income (loss)	2,679	(4,627)	(4,876)	(5,819)
Less: Net income attributable to noncontrolling interests	1,196	34	2,175	80
Net income (loss) attributable to the Partnership	$1,483	$(4,661)	$(7,051)	$(5,899)
Other Financial Data:				
Gross margin (2)	$33,829	$29,134	$93,677	$95,215
Adjusted EBITDA (2)	$35,787	$15,830	$92,192	$45,907

(1) Represents non-cash costs related to our Long-Term Incentive Plans.

(2) 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 September 30, 2016 Compared to Three Months Ended September 30, 2015

Total Revenue. Our total revenue for the three months ended September 30, 2016 was $63.8 million compared to $55.6 million for the three months ended September 30, 2015. This increase of $8.2 million was primarily due to the following:

- an increase in our Gathering and Processing Segment revenue of $2.4 million due to higher average throughput volumes of 38.7 MMcf/d, period over period, associated with our acquired Gulf of Mexico Pipeline,
- an increase in our Transmission Segment revenue of $4.4 million as a result of higher average throughput mainly related to our High Point system; and

Table of Contents

- an increase in our Terminals segment revenue of $1.4 million as a result of an increase in firm storage contracted capacity 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 September 30, 2016 were $26.1 million compared to $24.4 million for the three months ended September 30, 2015. This increase of $1.7 million was due to higher NGL and natural gas purchases of $1.4 million and $1.2 million, respectively. The increase in NGL and natural gas purchases are the result of higher NGL and natural gas prices and higher NGL and natural gas throughput volumes related to our Gathering and Processing segment.

Gross Margin. Gross margin for the three months ended September 30, 2016 was $33.8 million compared to $29.1 million for the three months ended September 30, 2015. This increase of $4.7 million was primarily due to higher segment gross margin in our Transmission segment of $4.5 million as a result of higher average throughput volumes and a $0.4 million increase in segment gross margin related to our Gathering and Processing segment. These increases were offset by a decrease of $0.2 million related to our Terminals segment primarily attributable to the liability classified awards offset by an increase in storage revenue.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2016 were $16.0 million compared to $15.3 million for the three months ended September 30, 2015. This increase of $0.7 million was primarily due to reclassifying equity based compensation expense related to the liability classified awards of $1.2 million from equity compensation expense to direct operating expenses due to the Partnership settling the awards in cash instead of equity. This was partly offset by decreased compressor rental expense of $0.5 million.

Selling, General and Administrative Expenses (SG&A). SG&A expenses for the three months ended September 30, 2016 were $13.3 million compared to $7.6 million for the three months ended September 30, 2015. This increase of $5.7 million was primarily due to an increase in transaction costs of $3.5 million comprised of an increase of $4.6 million related to our corporate relocation offset by a decrease of $1.1 million in acquisition costs. The remaining increase is attributable to salaries, wages, and insurance benefits of $0.8 million related to increased employee expenses as we transitioned from Denver to Houston, office lease expense of $0.4 million due to moving our corporate office and legal expense of $0.2 million in support of increased corporate activities.

Equity Compensation Expense. Equity compensation expense related to our Long-Term Incentive Plan for the three months ended September 30, 2016 was $0.1 million compared to $0.6 million for the three months ended September 30, 2015. The decrease of $0.5 million was primarily due to reclassifying equity based compensation expense related to the liability classified awards of $1.2 million from equity compensation expense to direct operating expenses due to the Partnership settling the awards in cash instead of equity, offset by additional equity compensation expense due to additional equity awards for certain executives in 2016.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended September 30, 2016 was $11.0 million compared to $9.2 million for the three months ended September 30, 2015. This increase of $1.8 million was primarily due to incremental depreciation of fixed assets related to our Gulf of Mexico Pipeline acquired in April 2016 and our Bakken system which began operations in October 2015.

Interest Expense. Interest expense for the three months ended September 30, 2016 was $5.2 million compared to $3.6 million for the three months ended September 30, 2015. This increase of $1.6 million was primarily due to higher outstanding borrowings under the Credit Agreement and an increase in our weighted average interest rate of 0.17%.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the three months ended September 30, 2016 was $11.0 million compared to $1.1 million for the three months ended September 30, 2015. This increase of

$9.9 million was primarily due to incremental earnings of $7.7 million related to our investment in Delta House and earnings of $2.9 million from the interests in the entities underlying the Emerald Transactions which were acquired in April 2016.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Total Revenue. Our total revenue for the nine months ended September 30, 2016 was $165.2 million compared to $187.8 million for the nine months ended September 30, 2015. This decrease of $22.6 million was primarily due to the following:

- a decrease in NGL revenues of $13.5 million due to lower gross NGL production volumes of 74.1 Mgal/d from our Gathering and Processing segment and lower realized NGL prices of $0.47/gal, which is a decrease of $0.13/gal period over period;
- a decrease in condensate revenues of $10.9 million due to lower realized condensate prices of $0.83/gal, which is a decrease of $0.17/gal, or 17.0%, period over period, and lower condensate production of 11.2 Mgal/d from our Gathering and Processing segment; and,

Table of Contents

- a decrease in natural gas revenue of $8.9 million due to lower realized natural gas prices of $2.48/Mcf, which is a decrease of $0.63/Mcf, or 20.3% period over period.

These decreases were partially offset by the following:

- an increase in crude oil gathering fee-based revenues of $4.4 million primarily due to incremental throughput volumes in our Gathering and Processing segment; and
- an increase in Terminals segment revenue of $3.2 million as a result of incremental storage utilization and contractual storage rate escalations.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the nine months ended September 30, 2016 were $65.1 million compared to $86.7 million for the nine months ended September 30, 2015. This decrease of $21.6 million was due to lower NGL and natural gas purchases of $12.1 million and $9.4 million, respectively. The decrease in NGL and natural gas purchases are the result of lower NGL and natural gas prices and volumes related to our Gathering and Processing segment.

Gross Margin. Gross margin for the nine months ended September 30, 2016 was $93.7 million compared to $95.2 million for the nine months ended September 30, 2015. This decrease of $1.5 million was primarily due to a decrease in segment gross margin in our Gathering and Processing segment of $4.5 million as a result of lower NGL and condensate production of 74.1 Mgal/d and 11.2 Mgal/d, respectively. The net decrease in our Gathering and Processing segment was partially offset by a $1.5 million increase in our Terminals segment primarily attributable to an increase in storage revenue and partially offset by expenses related to the liability classified awards and a $1.4 million increase related to our Transmission segment.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2016 were $46.8 million compared to $43.2 million for the nine months ended September 30, 2015. This increase of $3.6 million was primarily due to the liability classified awards of $1.2 million, $1.4 million in increased contract cost services mainly at Longview and the Gulf of Mexico Pipeline as well as $0.9 million increase in property taxes.

Selling, General and Administrative Expenses (SG&A). SG&A expenses for the nine months ended September 30, 2016 were $33.3 million compared to $20.1 million for the nine months ended September 30, 2015. This increase of $13.2 million was primarily due to an increase in transaction costs of $8.2 million comprised of an increase of $9.0 million related to our corporate relocation offset by a decrease of $0.8 million in acquisition costs. The remaining increase is attributable to salaries, wages and benefits of $1.8 million due to increased employee expenses as we transitioned from Denver to Houston, information and technology maintenance costs of $0.9 million primarily related to systems and licenses that were implemented in the prior year, legal and regulatory compliance fees of $0.7 million in support of corporate activities, contract services of $0.5 million, office lease expense of $0.5 million due to moving our corporate office.

Equity Compensation Expense. Equity compensation expense related to our Long-Term Incentive Plan for the nine months ended September 30, 2016 was $2.2 million compared to $2.8 million for the nine months ended September 30, 2015. This decrease of $0.6 million was primarily due to the reclassifying previously recognized equity based compensation expense of $0.6 million from equity compensation expense to direct operating expenses due to settling the awards in cash instead of equity, partially offset by additional equity compensation expense due to additional equity awards for certain executives in 2016.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the nine months ended September 30, 2016 was $32.0 million compared to $28.1 million for the nine months ended September 30, 2015. This increase of $3.9 million was primarily due to incremental depreciation of fixed assets related to our

Gulf of Mexico Pipeline acquired in April 2016 and our Bakken system which began operations in October 2015.

Interest Expense. Interest expense for the nine months ended September 30, 2016 was $19.5 million compared to $9.7 million for the nine months ended September 30, 2015. This increase of $9.8 million was primarily due to higher outstanding borrowings under the Credit Agreement, an increase in our weighted average interest rate of 0.77% and unfavorable unrealized losses on interest rate swaps.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the nine months ended September 30, 2016 were $30.0 million compared to $1.3 million for the nine months ended September 30, 2015. This increase of $28.7 million was primarily due to incremental earnings of $21.9 million related to our investment in Delta House and $7.4 million related to the interests in the entities underlying the Emerald Transactions which were acquired in April 2016.

Table of Contents

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 September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$43,163	$40,103	$116,091	$138,991
Gain (loss) on commodity derivatives, net	148	816	(719)	1,274
Total revenue	43,311	40,919	115,372	140,265
Purchases of natural gas, NGLs and condensate	23,794	22,055	60,206	79,645
Direct operating expenses	9,924	10,119	31,158	28,342
Other financial data:				
Segment gross margin (2)	$18,821	$18,422	$55,157	$59,687
Operating data:				
Average throughput (MMcf/d)	370.8	332.1	393.0	344.0
Average plant inlet volume (MMcf/d) (1)	105.5	120.7	103.4	125.5
Average gross NGL production (Mgal/d) (1)	145.1	203.1	180.3	254.4
Average gross condensate production (Mgal/d) (1)	91.7	88.2	88.4	99.6
Average realized prices:				
Natural gas ($/Mcf)	$2.95	$2.99	$2.48	$3.11
NGLs ($/gal)	$0.53	$0.51	$0.47	$0.60
Condensate ($/gal)	$0.89	$0.91	0.83	$1.00

(1) Excludes volumes and gross production under our elective processing arrangements.
(2) 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 September 30, 2016 Compared to Three Months Ended September 30, 2015

Revenue. Segment total revenue for the three months ended September 30, 2016 was $43.3 million compared to $40.9 million for the three months ended September 30, 2015. This increase of $2.4 million was primarily due to the following:

- higher realized NGL prices of 3.9%, offset by lower realized natural gas and condensate prices of 1.3% and 2.2%, respectively, and
- higher average throughput volumes of 38.7 MMcf/d, period over period, primarily due to incremental volumes associated with our acquired Gulf of Mexico Pipeline, offset by
- lower average NGL production of 58.0 Mgal/d primarily due to a decrease in NGL volumes received and processed at our Longview system, offset partially by our Chatom and Yellow Rose systems.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended September 30, 2016 were $23.8 million compared to $22.1 million for the three months ended September 30, 2015. This increase of $1.7 million was primarily due to higher purchase costs associated with our Magnolia, Chatom and Chapel Hill systems, period over period.

Table of Contents

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2016 was $18.8 million compared to $18.4 million for the three months ended September 30, 2015. Segment margin increased by $0.4 million due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses of $9.9 million and $10.1 million for the three months ended September 30, 2016 and 2015 remained consistent period over period.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Revenue. Segment total revenue for the nine months ended September 30, 2016 was $115.4 million compared to $140.3 million for the nine months ended September 30, 2015. This decrease of $24.9 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 20.3%, 21.7%, and 17.0%, respectively;
- lower average NGL and condensate production of 74.1 Mgal/d and 11.2 Mgal/d, respectively, primarily due to a decrease in NGL volumes for our Longview system; offset by
- higher average throughput volumes of 49.0 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 nine months ended September 30, 2016 were $60.2 million compared to $79.6 million for the nine months ended September 30, 2015. This decrease of $19.4 million was due to 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 nine months ended September 30, 2016 was $55.2 million compared to $59.7 million for the nine months ended September 30, 2015. This decrease of $4.5 million was primarily due to lower gross margin related mainly to our Longview, Chapel Hill and Lavaca systems due to lower production partially offset by increased gross margin from the Gulf of Mexico Pipeline.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2016 were $31.2 million compared to $28.3 million for the nine months ended September 30, 2015. This increase of $2.9 million was primarily due to $1.4 million in higher contract cost services at Longview and the Gulf of Mexico Pipeline, $0.9 million increase in property taxes and $0.4 million measurement equipment cost related to Bakken, which commenced operations in October 2015.

Transmission Segment

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

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Transmission segment				
Financial data:				
Total revenue	$14,367	$9,977	$33,332	$34,148
Purchases of natural gas, NGLs and condensate	2,288	2,376	4,890	7,097

Direct operating expenses	2,915	3,595	9,181	10,027
Other financial data:				
Segment gross margin (1)	$12,071	$7,581	$28,419	$26,975
Operating data:				
Average throughput (MMcf/d)	713.8	693.8	679.6	733.4
Average firm transportation - capacity reservation (MMcf/d)	748.2	623.6	655.3	658.4
Average interruptible transportation - throughput (MMcf/d)	326.2	405.3	365.4	421.9

Table of Contents

(1) 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 September 30, 2016 Compared to Three Months Ended September 30, 2015

Revenue. Segment total revenue for the three months ended September 30, 2016 was $14.4 million compared to $10.0 million for the three months ended September 30, 2015. This increase of $4.4 million was primarily due to higher average throughput volumes of 20.0 MMcf/d primarily attributable to our High Point system.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended September 30, 2016 of $2.3 million compared to $2.4 million for the three months ended September 30, 2015. This decrease of $0.1 million was primarily due to a decline in realized natural gas prices of $0.04 and lower volumetric throughput associated with our fixed margin arrangements.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2016 was $12.1 million compared to $7.6 million for the three months ended September 30, 2015. This increase of $4.5 million was primarily due to the higher average throughput volumes of 20.0 MMcf/d or 2.9% noted above, primarily attributable to the High Point system, period over period.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2016 were $2.9 million compared with the $3.6 million for the three months ended September 30, 2015. This decrease of $0.7 million was primarily attributable to an ongoing cost cutting effort to reduce operating expenses.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Revenue. Segment total revenue for the nine months ended September 30, 2016 was $33.3 million compared to $34.1 million for the nine months ended September 30, 2015. This decrease of $0.8 million was primarily due to lower average throughput volumes of 53.8 MMcf/d.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the nine months ended September 30, 2016 of $4.9 million compared to $7.1 million for the nine months ended September 30, 2015. This decrease of $2.2 million was primarily due to lower volumetric throughput and a decline in realized natural gas prices of $0.63 associated with our fixed margin arrangements.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2016 was $28.4 million compared to $27.0 million for the nine months ended September 30, 2015. Segment margin increased by $1.4 million due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2016 were $9.2 million compared with the $10.0 million for the nine months ended September 30, 2015. This decrease of $0.8 million was primarily related to an ongoing cost cutting effort to reduce operating expenses.

Terminals Segment

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

Table of Contents

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Segment Financial and Operating Data:				
Terminals segment				
Financial data:				
Total revenue	$6,140	$4,745	$16,516	$13,346
Direct operating expenses	3,203	1,614	6,415	4,793
Other financial data:				
Segment gross margin (2)	$2,937	$3,131	$10,101	$8,553
Operating data:				
Contracted Capacity (Bbls)	2,224,067	1,587,900	1,920,533	1,453,678
Design Capacity (Bbls)	2,342,467	1,784,133	2,098,022	1,651,667
Storage utilization (1)	94.9 %	89.0 %	91.5 %	88.0 %

(1) Excludes storage utilization associated with our discontinued operations.
(2) 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 September 30, 2016 Compared to Three Months Ended September 30, 2015

Revenue. Segment total revenue for the three months ended September 30, 2016 was $6.1 million compared to $4.7 million for the three months ended September 30, 2015. The increase of $1.4 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at the Harvey and Westwego terminals and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2016 was $3.2 million compared to $1.6 million for the three months ended September 30, 2015. The increase of $1.6 million was primarily related to the liability classified awards of $1.2 million.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2016 was $2.9 million compared to $3.1 million for the three months ended September 30, 2015. The decrease of $0.2 million was primarily attributable to the liability classified awards, partially offset by an increase in storage revenue.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Revenue. Segment total revenue for the nine months ended September 30, 2016 was $16.5 million compared to $13.3 million for the nine months ended September 30, 2015. The increase of $3.2 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 nine months ended September 30, 2016 was $6.4 million compared to $4.8 million for the nine months ended September 30, 2015. The increase of $1.6 million was primarily related to the liability classified awards of $1.2 million.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2016 was $10.1 million compared to $8.6 million for the nine months ended September 30, 2015. The increase of $1.5 million was primarily attributable to an increase in storage revenue that was partially offset by the liability classified awards.

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 (as defined herein), 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 secured and unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that the sources of liquidity

Table of Contents

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 nine months ended September 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 nine months ended September 30, 2016. Our liquidity in that period was also impacted by borrowings under our Credit Agreement to fund ongoing capital growth projects and the issuance of the 3.77% Senior Notes.

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 September 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 nine months ended September 30, 2016, we sold 248,561 common units for proceeds of $3.0 million, net of commissions and accrued offering costs of $0.2 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 September 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 (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.

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 certain cash distributions and acquisitions. 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.

Subsequently, on September 30, 2016 and in connection with entering into the 3.77% Note Purchase Agreement , the Partnership entered into the Limited Waiver and Third Amendment to the Credit Agreement, which among other things, (i) allows Midla Holdings (as defined below), for so long as the 3.77% Senior Notes are outstanding, to be excluded from guaranteeing the obligations under the Credit Agreement and being subject to certain covenants thereunder, (ii) releases of the lien granted under the Credit Agreement related to D-Day's equity interests in FPS Equity, and (iii) deems the FPS Equity excluded property under the Credit Agreement. All other terms under the Credit Agreement remain the same.

Table of Contents

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 (i) the Federal Funds Rate, plus 0.50%, (ii) 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 (iii) 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.

The Credit Agreement also contains customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

At September 30, 2016 and December 31, 2015, letters of credit outstanding under the Credit Agreement were $7.6 million and $1.8 million, respectively.

As of September 30, 2016, our consolidated total leverage ratio was 4.43 and our interest coverage ratio was 7.18, 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 September 30, 2016. As of September 30, 2016, we had approximately $672.7 million of outstanding borrowings under 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.

3.77% Senior Notes

On September 30, 2016, Midla Financing, Midla, and MLGT entered into the 3.77% Senior Note Purchase Agreement with the Purchasers. Pursuant to the 3.77% Senior Note Purchase Agreement, Midla Financing sold $60.0 million in aggregate principal amount of Senior Notes to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly. The average quarterly principal payment is approximately $1.1 million. Principal on the 3.77% Senior Notes will be paid on the last business day of each fiscal quarter end starting June 30, 2017. The 3.77% Senior Notes are payable in full on June 30, 2031. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million (after deducting related issuance costs). The proceeds are contractually restricted.

The Note Purchase Agreement includes customary representations and warranties, affirmative and negative covenants (including financial covenants), and events of default that are customary for a transaction of his type. Many of these provisions apply not only to Midla Financing and the Note Guarantors, but also to American Midstream Midla Financing Holdings, LLC (“Midla Holdings”), a wholly owned subsidiary of the Partnership and the sole member of Midla Financing. Among other things, Midla Financing must maintain a debt service reserve account containing six months of principal and interest payments, and Midla Financing and the Note Guarantors (including any entities that become guarantors under the terms of the 3.77% Senior Note Purchase Agreement) are restricted from making

distributions (a) until June 30, 2017, (b) unless the debt service coverage ratio is not less than, and is not projected to be for the following 12 calendar months less than, 1.20:1.00, and (c) unless certain other requirements are met.

In connection with the 3.77% Senior Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing's obligations under the 3.77% Senior Note Purchase Agreement. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible personal property, including the membership interests in each Note Guarantor held by Midla Financing, and Financing Holdings pledged the membership interests in Midla Financing to the Collateral Agent.

Net proceeds from the 3.77% Senior Notes are restricted and will be used (1) to fund project costs incurred in connection with (a) the construction of the Midla-Natchez Line (b) the retirement of Midla's existing 1920's vintage pipeline (c) the move of our Baton

Table of Contents

Rouge operations to the MLGT system (d) the reconfiguration of the DeSiard compression system and all related ancillary facilities, (2) to pay transaction fees and expenses in connection with the issuance of the 3.77% Senior Notes, and (3) for other general corporate purposes of Midla Financing.

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 $20.4 million at September 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):

	Nine months ended September 30,	
	2016	2015
Net cash provided by (used in):		
Operating activities	$36,327	$31,631
Investing activities	(192,859)	(152,312)
Financing activities	161,411	120,182

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Operating Activities. Net cash provided by operating activities was $36.3 million for the nine months ended September 30, 2016 compared to $31.6 million for the nine months ended September 30, 2015. Net cash provided by operating activities for the nine months ended September 30, 2016 increased by $4.7 million period over period as a result of an increase in depreciation, amortization and accretion expense of $3.9 million due to our Gulf of Mexico Pipeline acquisition, an increase in amortization in deferred financing costs of $0.6 million, an increase in operating assets and liabilities of $0.5 million and an increase in distributions from unconsolidated affiliates of $28.2 million offset by an increase in earnings in unconsolidated affiliates of $28.7 million.

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 $192.9 million for the nine months ended September 30, 2016 compared to $152.3 million for the nine months ended September 30, 2015. Net cash used in investing activities for the nine months ended September 30, 2016 increased by $40.6 million primarily due to funds used to acquire our interests underlying the Emerald Transactions of $100.9 million, change in restricted cash of $50.2 million, higher

costs of acquisitions of $10.1 million period over period and a $4.7 million decrease in cash proceeds received on the disposition of assets.

These increases in cash used in investing activities were partially offset lower investments in unconsolidated affiliates of $51.3 million related to investments in unconsolidated affiliates period over period, $46.0 million of lower capital expenditures as a result of a decrease in growth capital projects in process and $28.0 million of higher cash distributions received from investments in unconsolidated affiliates as a return of capital.

Financing Activities. Net cash provided by financing activities was $161.4 million for the nine months ended September 30, 2016 compared to $120.2 million for the nine months ended September 30, 2015. Cash provided by financing activities for the nine months ended September 30, 2016 increased by $41.2 million primarily due to the absence of third quarter 2015 cash distributions in excess of carrying value of $100.6 million to our General Partner related to the Delta House Acquisition, $60.0 million of

Table of Contents

proceeds received related to the issuance of the 3.77% Senior Notes and higher net borrowings on our Credit Agreement of $11.9 million.

This increase in cash provided by financing activities was partially offset by a $78.1 million decrease in proceeds from the issuance of our common stock to the public, a $45 million decrease in the issuance of Series A Units and a $9.8 million increase in unitholder distributions.

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 September 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 September 30, 2016, our off-balance sheet arrangements changed by $16.0 million, as a result of the executed 16-year office lease, from those listed in “Contractual Obligations” within Item 7: Management’s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report filed on March 7, 2016.

Capital Requirements

The energy business is capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities. We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets) made to maintain our operating income or operating capacity; or

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

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the nine months ended September 30, 2016, capital expenditures totaled $65.9 million, including expansion capital expenditures of $62.2 million, maintenance capital expenditures of $1.7 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 $2.0 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 October 20, 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 September 30, 2016, or $1.65 per common unit on an annualized basis. The cash distribution is expected to be paid on November 14, 2016, to unitholders of record as of the close of business on November 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.

Table of Contents

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 September 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 September 30, 2016, we economically hedged approximately 34% of our expected exposure to NGL prices and 51% 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 September 30, 2016:

Commodity	Instrument	Volumes (1)	Weighted Average Price	Period	Fair Value

					(in thousands)
NGLs (gal)	Swaps	(2,249,400)	$0.65	October 2016 - December 2016	$ (275)
Oil (Bbl)	Swaps	(10,580)	$45.77	October 2016 - December 2016	(34)
					$ (309)

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

Table of Contents

Interest Rate Risk

During the nine months ended September 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 $3.1 million for the nine months ended September 30, 2016.

Table of Contents

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 September 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 September 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.

Table of Contents

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.

We and our general partner will incur substantial transaction-related costs in connection with the LP Merger, the GP Merger and related transactions (collectively, the “Merger Transactions”).

We and the other parties to the LP Merger and the GP Merger expect to incur non-recurring transaction-related costs associated with completing the Merger Transactions, which are currently estimated to total approximately $10 million, excluding expenses associated with expected financings, which expenses could be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal counsel, financial advisors, accountants and auditors and governmental filing fees. There can be no assurance that the elimination of certain costs due to the fact that JPE will no longer be publicly traded will offset the incremental transaction-related costs over time. Thus, any net cost savings may not be achieved in the near term, the long term or at all.

We are exposed to certain risks during the pendency of the Merger Transactions. The Merger Transactions are subject to conditions beyond our control and may not be completed, and failure to complete, or significant delays in

completing, the Merger Transactions could negatively affect the trading price of our common units and our future business and financial results.

Completion of the Merger Transactions is not assured and is subject to risks, including the risks that approval of the merger by the JPE unitholders or by governmental agencies is not obtained or that other closing conditions are not satisfied. Each merger agreement contains conditions that, if not satisfied or waived, would result in the applicable merger not occurring, even though the JPE unitholders may have voted in favor of the LP Merger proposals presented to them. Satisfaction of some of the conditions to the mergers, such as receipt of required regulatory approvals, is not entirely in the control of the parties to the merger agreements. In addition, we and the other parties to each merger agreement can agree not to consummate the merger even if all approvals have been obtained. The closing conditions to a merger may not be satisfied, and we or the other parties to the applicable merger agreement may choose not to, or may be unable to, waive an unsatisfied condition, which may cause such merger not to

Table of Contents

occur. If the Merger Transactions are not completed, or if there are significant delays in completing the Merger Transactions, the trading price of our common units and our future business and financial results could be negatively affected.

In connection with the Merger Transactions, we will be subject to several risks, including the following:

- negative reactions from the financial markets if the anticipated benefits from the Merger Transactions are not realized or if the Merger Transactions are not completed, including declines in the price of our common units due to the fact that current prices may reflect a market assumption that the Merger Transactions will be completed;
- potential issues with customers or suppliers that could negatively impact earnings and cash flow regardless of whether the Merger Transactions are consummated;
- potential loss of key personnel during the pendency of the Merger Transactions;
- the attention of our management will have been diverted to the Merger Transactions rather than our operations and pursuit of other opportunities that could have been beneficial to us, some of which alternate activities are restricted under the merger agreements; and
- having to pay certain significant costs relating to the Merger Transactions, as discussed above.

Table of Contents

Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (filed as Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated April 25, 2016 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
3.3	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	Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated October 31, 2016 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 4, 2016).
3.5	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).
3.6	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	Note Purchase and Guaranty Agreement by and among American Midstream Midla Financing, LLC, American Midstream (Midla), LLC, Mid Louisiana Gas Transmission LLC and certain institutional investors dated September 30, 2016 (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001- 35257) filed on October 6, 2016).
10.2	Limited Waiver and Third Amended and Restated Credit Agreement among American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP, Bank of America, N.A., the guarantors party thereto and the lenders party thereto, dated September 30, 2016 (filed as Exhibit 10.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on October 6, 2016).
10.3*	Unit Purchase Option Grant Notice by and between American Midstream GP, LLC and Eric T. Kalamaras, dated August 26, 2016.
10.4*	American Midstream GP, LLC Long-Term Incentive Plan Grant of Phantom Units by and between American Midstream GP, LLC and Eric T. Kalamaras, dated July 26, 2016.
10.5*	Transition and Release and Waiver Agreement by and between American Midstream GP, LLC and Daniel C. Campbell, dated September 2, 2016.
10.6*	Offer Letter to Eric T. Kalamaras.
10.7*	Offer Letter to Michael Croney.
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 September 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 September 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 September 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 September 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.

Table of Contents

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: November 7, 2016

AMERICAN MIDSTREAM PARTNERS, LP

By: American Midstream GP, LLC, its general partner

By: /s/ Lynn L. Bourdon III
Lynn L. Bourdon III
Chairman, President and Chief Executive Officer
(principal executive officer)

By: /s/ Eric T. Kalamaras
Eric T. Kalamaras
Senior Vice President and Chief Financial Officer
(principal financial officer)

Table of Contents

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Table of Contents

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*	Furnished herewith.
**	Submitted electronically herewith.