

American Midstream Partners, LP
Form 10-Q
May 12, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2014

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 001-35257

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

Delaware

27-0855785

(State or other jurisdiction of
incorporation or organization)

(I.R.S. Employer
Identification No.)

1400 16th Street, Suite 310

Denver, CO

80202

(Address of principal executive offices)

(Zip code)

(720) 457-6060

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

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 No

There were 11,139,729 common units, 5,353,970 Series A Units and 1,168,225 Series B Units of American Midstream Partners, LP outstanding as of May 8, 2014. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

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Glossary of Terms

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

Bbl Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.

Bcf One billion cubic feet.

Condensate Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.

/d Per day.

FERC Federal Energy Regulatory Commission.

Fractionation Process by which natural gas liquids are separated into individual components.

GAAP Accounting principles generally accepted in the United States of America

Gal Gallons.

Mcf One thousand cubic feet.

MMcf One million cubic feet.

Mgal One thousand gallons

NGL or NGLs Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

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

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Balance Sheets

(Unaudited, in thousands)

	March 31, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	\$2,022	\$393
Accounts receivable	7,870	6,822
Unbilled revenue	24,900	22,005
Risk management assets	189	473
Other current assets	9,914	7,497
Current assets held for sale	1,582	1,268
Total current assets	46,477	38,458
Property, plant and equipment, net	365,252	312,510
Goodwill	16,253	16,447
Intangible assets, net	50,692	3,682
Other assets, net	8,819	9,064
Noncurrent assets held for sale, net	1,912	1,914
Total assets	\$489,405	\$382,075
Liabilities, Equity and Partners' Capital		
Current liabilities		
Accounts payable	\$1,592	\$3,261
Accrued gas purchases	17,534	16,394
Accrued expenses and other current liabilities	15,969	15,058
Current portion of long-term debt	1,427	2,048
Risk management liabilities	488	423
Current liabilities held for sale	1,383	1,106
Total current liabilities	38,393	38,290
Risk management liabilities	75	101
Asset retirement obligations	34,827	34,636
Other liabilities	270	191
Long-term debt	125,650	130,735
Deferred tax liability	4,542	4,749
Noncurrent liabilities held for sale, net	82	95
Total liabilities	203,839	208,797
Commitments and contingencies (see Note 13)		
Convertible preferred units		
Series A convertible preferred units (5,354 thousand and 5,279 thousand units issued and outstanding as of March 31, 2014, and December 31, 2013, respectively)	96,654	94,811
Equity and partners' capital		
General partner interest (235 thousand and 185 thousand units issued and outstanding as of March 31, 2014, and December 31, 2013, respectively)	(3,747)) 2,696
Limited partner interest (11,135 thousand and 7,414 thousand units issued and outstanding as of March 31, 2014, and December 31, 2013, respectively)	157,910	71,039

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Series B convertible units (1,168 thousand and zero units issued and outstanding as of March 31, 2014, and December 31, 2013, respectively)	30,000	—
Accumulated other comprehensive income	140	104
Total partners' capital	184,303	73,839
Noncontrolling interests	4,609	4,628
Total equity and partners' capital	188,912	78,467
Total liabilities, equity and partners' capital	\$489,405	\$382,075

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

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

	Three months ended March 31,	
	2014	2013
Revenue	\$ 75,979	\$ 59,707
Loss on commodity derivatives, net	(130) (305
Total revenue	75,849	59,402
Operating expenses:		
Purchases of natural gas, NGLs and condensate	50,924	47,301
Direct operating expenses	8,850	4,803
Selling, general and administrative expenses	5,593	3,425
Equity compensation expense	360	388
Depreciation, amortization and accretion expense	7,632	5,646
Total operating expenses	73,359	61,563
Gain on involuntary conversion of property, plant and equipment	—	421
Loss on sale of assets, net	(21) —
Operating income (loss)	2,469	(1,740
Other expense:		
Interest expense	(1,903) (1,731
Net income (loss) before income tax benefit	566	(3,471
Income tax benefit	11	—
Net income (loss) from continuing operations	577	(3,471
Discontinued operations:		
(Loss) income from operations of disposal groups, net of tax	(69) 73
Net income (loss)	508	(3,398
Net income attributable to noncontrolling interests	108	155
Net income (loss) attributable to the Partnership	\$ 400	\$ (3,553
General partner's interest in net income (loss)	\$ 7	\$ (70
Limited partners' interest in net income (loss)	\$ 393	\$ (3,483
Limited partners' net (loss) income per common unit (See Note 4 and Note 10):		
Basic and diluted:		
Loss from continuing operations	\$(0.31) \$(0.39
(Loss) income from discontinued operations	(0.01) 0.01
Net loss	\$(0.32) \$(0.38
Weighted average number of common units outstanding:		
Basic and diluted	9,846	9,167

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

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

	Three months ended March 31,	
	2014	2013
Net income (loss)	\$ 508	\$(3,398)
Unrealized gain (loss) on post retirement benefit plan assets and liabilities	36	(13)
Comprehensive income (loss)	544	(3,411)
Less: Comprehensive income attributable to noncontrolling interests	108	155
Comprehensive income (loss) attributable to Partnership	\$ 436	\$(3,566)

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

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

	General Partner Interest	Limited Partner Interest	Series B Convertible Units	Accumulated Other Comprehensive Income	Total Partners' Capital	Noncontrolling Interest
Balances at December 31, 2012	\$548	\$79,266	\$—	\$351	\$80,165	\$7,438
Net income (loss)	(70)	(3,483)	—	—	(3,553)	155
Unitholder distributions	(80)	(3,964)	—	—	(4,044)	—
Net distributions to noncontrolling interest holders	—	—	—	—	—	(210)
LTIP vesting	(183)	183	—	—	—	—
Tax netting repurchase	—	(74)	—	—	(74)	—
Unit based compensation	388	—	—	—	388	—
Other comprehensive loss	—	—	—	(13)	(13)	—
Balances at March 31, 2013	\$603	\$71,928	\$—	\$338	\$72,869	\$7,383
Balances at December 31, 2013	\$2,696	\$71,039	\$—	\$104	\$73,839	\$4,628
Net income	7	393	—	—	400	108
Issuance of common units to public, net of offering costs	—	86,926	—	—	86,926	—
Issuance of Series B convertible units	—	—	30,000	—	30,000	—
Unitholder contributions	1,276	—	—	—	1,276	—
Unitholder distributions	(524)	(8,037)	—	—	(8,561)	—
Issuance and exercise of warrant	(7,164)	7,164	—	—	—	—
Net distributions to noncontrolling interest owners	—	—	—	—	—	(98)
Acquisition of noncontrolling interest	—	21	—	—	21	(29)
LTIP vesting	(366)	494	—	—	128	—
Tax netting repurchase	—	(90)	—	—	(90)	—
Unit based compensation	328	—	—	—	328	—
Other comprehensive income	—	—	—	36	36	—
Balances at March 31, 2014	\$(3,747)	\$157,910	\$30,000	\$140	\$184,303	\$4,609

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

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

	Three months ended March 31,	
	2014	2013
Cash flows from operating activities		
Net income (loss)	\$ 508	\$(3,398)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	7,632	5,678
Amortization of deferred financing costs	428	283
Amortization of weather derivative premium	284	—
Unrealized loss on commodity derivatives	39	481
Equity based compensation	360	388
OPEB plan net periodic cost	12	18
Gain on involuntary conversion of property, plant and equipment	—	(421)
Deferred tax benefit	(26))
Changes in operating assets and liabilities, net:		
Accounts receivable	(1,041)) 715
Unbilled revenue	(3,222)) (1,516)
Other current assets	(2,374)) (1,020)
Other assets, net	(15)) (59)
Accounts payable	(789)) (787)
Accrued gas purchases	1,416	1,325
Accrued expenses and other current liabilities	263	(525)
Other liabilities	79	(59)
Net cash provided by operating activities	3,554	1,103
Cash flows from investing activities		
Cost of acquisitions	(110,909)) —
Additions to property, plant and equipment	(3,928)) (8,052)
Proceeds from disposals of property, plant and equipment	6,135	—
Insurance proceeds from involuntary conversion of property, plant and equipment	—	560
Net cash used in investing activities	(108,702)) (7,492)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	86,926	—
Unitholder contributions	1,276	—
Unitholder distributions	(5,379)) (4,044)
Issuance of Series B Units	30,000	—
Acquisition of noncontrolling interest	(8)) —
Net distributions to noncontrolling interest owners	(98)) (210)
LTIP tax netting unit repurchase	(90)) (74)
Payments of deferred debt issuance costs	(144)) (912)
Payments on other debt	(791)) (358)
Borrowings on other debt	170	1,476
Payments on long-term debt	(49,771)) (17,585)
Borrowings on long-term debt	44,686	27,565
Net cash provided by financing activities	106,777	5,858
Net increase (decrease) in cash and cash equivalents	1,629	(531)

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Cash and cash equivalents		
Beginning of period	393	576
End of period	\$ 2,022	\$ 45
Supplemental cash flow information		
Interest payments, net	\$ 1,781	\$ 1,487
Supplemental non-cash information		
Decrease in accrued property, plant and equipment	\$(1,474) \$(3,977
The accompanying notes are an integral part of these condensed consolidated financial statements.		

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American Midstream Partners, LP and Subsidiaries
Notes to Condensed Consolidated Financial Statements
(Unaudited)

1. Organization and Basis of Presentation

Nature of Business

American Midstream Partners, LP (the "Partnership"), was formed on August 20, 2009 as a Delaware limited partnership for the purpose of operating, developing and acquiring a diversified portfolio of midstream energy assets. We provide natural gas gathering, treating, processing, fractionating, marketing and transportation services primarily in the Gulf Coast and Southeast regions of the United States through our ownership and operation of eleven gathering systems, two processing facilities, one fractionation facility, four terminal sites, three interstate pipelines and five intrastate pipelines. In addition, we own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Through our four marine terminal sites, we provide petroleum, agricultural, and chemical liquid storage services.

We hold our assets in a series of wholly owned limited liability companies, a limited partnership and a corporation. Our capital accounts consist of general partner interests and limited partner interests.

Our interstate natural gas pipeline assets transport natural gas through the FERC regulated interstate natural gas pipelines in Louisiana, Mississippi, Alabama and Tennessee. Our interstate pipelines include:

High Point Gas Transmission, LLC, which owns and operates approximately 400 miles of intrastate pipeline and is connected to 40 meters with 32 active producers and offers processing options at the Toca processing plant with delivery to Southern Natural Gas available downstream of the processing plant in Louisiana;

American Midstream (Midla), LLC, which owns and operates approximately 370 miles of interstate pipeline that runs from the Monroe gas field in northern Louisiana south through Mississippi to Baton Rouge, Louisiana;

American Midstream (AlaTenn), LLC, which owns and operates approximately 295 miles of interstate pipeline that runs through the Tennessee River Valley from Selmer, Tennessee, to Huntsville, Alabama and serves an eight-county area in Alabama, Mississippi and Tennessee.

Equity Offering and Series B Convertible Units Issuance

In January 2014, in connection with the Lavaca Acquisition as discussed in Note 3, the Partnership completed a public equity offering resulting in net proceeds of \$86.9 million and the issuance to our General Partner of 1,168,225 Series B convertible units ("Series B Units") representing Series B limited partnership interests in the Partnership. The Series B Units have the right to share in distributions from the Partnership on a pro-rata basis with holders of the Partnership's common units and will convert into common units on a one-for-one basis on January 31, 2016.

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 complete financial statements. The year-end balance sheet data was derived from consolidated audited financial statements but does not include disclosures required by GAAP for annual periods. We have made reclassifications to amounts reported in prior period condensed consolidated financial statements to conform to our current year presentation. These reclassifications did not have an impact on net income for the period previously reported. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the respective interim periods.

Our financial results for the three months ended March 31, 2014 are not necessarily indicative of the results that may be expected for the full year ended December 31, 2014. These unaudited condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in i) our Annual Report on Form 10-K for the year ended December 31, 2013 ("Annual Report") filed on March 11, 2014 and ii) our Annual Report on Form 10-K/A that was filed with the Securities and Exchange Commission ("SEC") on May 12, 2014 which updated portions of our annual report.

Consolidation Policy

Our condensed consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. We hold a 50% undivided interest in the Burns Point gas processing facility in which we are responsible for our proportionate share of the costs and expenses of the facility. Our condensed consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of this undivided interest. As of March 31, 2014, we also hold a 92.2% undivided

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interest in the Chatom Processing and Fractionation facility (the "Chatom System"). Our condensed consolidated financial statements reflect the accounts of the Chatom System and the interests in the Chatom System held by non-affiliated working interest owners are reflected as noncontrolling interests in the Partnership's condensed consolidated financial statements.

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 judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things i) estimating unbilled revenues, accrued gas purchases and operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

2. Recent Accounting Pronouncements

In July 2013, the FASB issued Accounting Standards Codification ("ASC ") No. 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a consensus of the FASB Emerging Issues Task Force). This guidance was issued related to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The updated guidance requires an entity to net its unrecognized tax benefits against the deferred tax assets for all same jurisdiction net operating loss carryforward, a similar tax loss, or tax credit carryforwards. A gross presentation will be required only if such carryforwards are not available or would not be used by the entity to settle any additional income taxes resulting from disallowance of the uncertain tax position. The update was effective for the Partnership effective January 1, 2014 and did not have a material impact on its condensed consolidated financial statements.

In April 2014, the FASB issued ASC No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance amends the definition of discontinued operations to include components of an entity that have been disposed of, meet the criteria to be classified as held-for-sale, or has been abandoned/spun-off; and represents a strategic shift that has, or will have, a major effect on an entity's operations and financial results. The update applies to disposals and classifications as held-for-sale that occur after the effective date. The update is effective for all periods beginning after December 15, 2014 and is not expected to have a material impact on the Partnership.

3. Acquisitions and Divestitures

Lavaca Acquisition

On January 31, 2014, the Partnership acquired approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas, the ("Lavaca Acquisition"). The consideration for the Lavaca Acquisition was financed with a portion of the net proceeds from the Partnership's January 2014 equity offering of \$86.9 million and proceeds of \$30.0 million from the issuance to our General Partner of 1,168,225 Series B Units.

The Lavaca Acquisition qualified as a business combination according to ASC 805, Business Combinations, and, as such, the Partnership engaged a third party to estimate the fair value of the assets as of the effective date of the acquisition. A combination of the income and cost approaches were utilized to estimate the fair value of the assets. These fair value measurements are based on significant inputs not observable in the market and thus represent a Level 3 measurement as defined by ASC 820, Fair Value Measurement.

Primarily using the cost approach to value the physical assets, the fair value estimates are based on i) replacement cost estimates using third party data based on installations of similar assets including an economic obsolescence factor and ii) estimated depreciation on the assets based on third party sources and analysis of the life and use of the assets.

It was determined as part of the fair value analysis of the acquisition, that the Partnership acquired separately identifiable intangible assets. The Lavaca Acquisition includes a 25-year gas gathering agreement which states that Penn Virginia Corporation (NYSE:

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PVA ("PVA") will dedicate certain acreage and all related future production to the gathering infrastructure included in the acquisition. In accordance with ASC 805, contract based intangible assets include the value of rights derived from contractual agreements. The Partnership will receive incremental value from PVA's development of the reserves within the dedicated acreage and, therefore, it was determined that the dedicated acreage represents intangible assets acquired with the Lavaca Acquisition. The Partnership will amortize the Lavaca Acquisition intangibles using the straight-line method over the 25-year life of the related gas gathering agreement. The Partnership will amortize the Lavaca Acquisition intangibles using the straight-line method over the life of the related gas gathering agreement and recognize \$1.9 million of amortization expense annually over the gas gathering agreement.

Primarily using the income approach to value the intangible assets, the fair value estimates are based on: i) an assumed discount rate of 10.5%; ii) present value of estimated EBITDA; iii) estimated timing and amounts of future operating and development costs; iv) forward market prices as of December 2013 for natural gas and crude oil; and v) an increase in throughput volumes through 2019, declining thereafter.

The Partnership completed a preliminary purchase price allocation to determine the estimated fair value of the acquired assets. The preliminary allocation is subject to various purchase price adjustments, which could impact the allocation presented below. The following table summarizes the preliminary purchase price allocation for the Lavaca Acquisition (in thousands):

Property, plant and equipment:

Land	\$2
Pipelines	55,654
Equipment	753
Total property, plant and equipment	56,409
Intangible assets	48,000
Total cash consideration	\$ 104,409

For the three months ended March 31, 2014, Lavaca contributed \$2.3 million of revenue and \$1.6 million of net income attributable to the Partnership's Gathering and Processing segment, which are included in the condensed consolidated statement of operations.

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 that is consistent with the operations under the current agreement is not available.

Other Acquisition

In the fourth quarter of 2013, High Point Gas Gathering LLC, a subsidiary of the Partnership, entered into a purchase and sale agreement to acquire natural gas pipeline facilities and interests thereto for approximately \$6.5 million that are contiguous to, and connect with, our High Point System in offshore Louisiana; the ("Williams Pipeline Acquisition"). The closing of the purchase and sale agreement was subject to FERC approval of the seller's application to abandon by sale to us the pipeline facilities and to permit the facilities to serve a gathering function, exempt from FERC's jurisdiction. The FERC granted approval of the application during the first quarter of 2014, and the purchase and sale agreement closed on March 14, 2014. Total consideration was allocated to pipeline fixed assets using the income approach based on Level 3 inputs.

Blackwater Terminals Acquisition

Effective December 17, 2013, we acquired Blackwater Midstream Holdings, LLC ("Blackwater"), which operates 1.3 million barrels of storage capacity across four marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland.

For the three months ended March 31, 2014, Blackwater contributed \$3.6 million of revenue and \$0.9 million of net income attributable to the Partnership's Terminals segment, which are included in the condensed consolidated statement of operations.

High Point System Acquisition

Effective April 15, 2013, our General Partner contributed to us the High Point System, consisting of 100% of the limited liability company interests in High Point Gas Transmission, LLC and High Point Gas Gathering, LLC. The High Point System entities own midstream assets consisting of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana, in the Plaquemines and St. Bernard's Parishes, and the shallow water and deep shelf Gulf of Mexico, including the Mississippi

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Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound zones. Natural gas is collected at more than 75 receipt points that connect hundreds of wells with an emphasis on oil and liquids-rich reservoirs.

For the three months ended March 31, 2014, the High Point System contributed \$7.0 million of revenue and \$4.7 million of net income attributable to the Partnership's Transmission segment, which are included in the condensed consolidated statement of operations.

Madison Divestiture

On March 31, 2014, the Partnership completed the sale of certain gathering and processing assets in Madison County, Texas. We received \$6.1 million in cash proceeds related to the sale. The Partnership recognized a \$3.0 million impairment charge related to these assets for the year ended December 31, 2013, which wrote down the assets to a carrying value of \$6.1 million as of December 31, 2013.

4. Discontinued Operations

We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

During the second quarter of 2013, the board of directors of our General Partner approved a plan to sell certain non-strategic gathering and processing assets which meet specific criteria, qualifying them as held for sale. Subsequently, as part of the Blackwater Acquisition described in Note 3, we acquired long-lived terminal assets classified as held for sale.

As a result of the planned divestiture of these non-strategic midstream assets, we have accounted for these disposal groups as discontinued operations within our Gathering and Processing and Terminal segments. Accordingly, we reclassified and excluded the disposal groups' results of operations from our results of continuing operations and reported the disposal groups' results of operations as (Loss) income from operations of disposal groups, net of tax in our accompanying condensed consolidated statement of operations for all periods presented. We did not, however, elect to present separately the operating, investing and financing cash flows related to the disposal groups in our accompanying condensed consolidated statement of cash flows as this activity was immaterial for all periods presented. The following table presents the revenue and expenses and (Loss) income from operations of disposal groups, net of tax associated with the assets classified as held for sale for the three months ended March 31, 2014 and 2013 (in thousands, except per unit amounts):

	Three months ended March 31,	
	2014	2013
Revenue	\$ 4,626	\$ 3,638
Expense	(4,685) (3,565
Loss on sale of assets	(22) —
Income tax benefit	12	—
(Loss) income from operations of disposal groups, net of tax	\$ (69) \$ 73
Limited partners' net (loss) income per unit from discontinued operations (basic and diluted)	\$ (0.01) \$ 0.01

5. Concentration of Credit Risk and Trade Accounts Receivable

Our primary market areas are located in the United States along the Gulf Coast and in the Southeast. We have a concentration of trade receivable balances due from companies engaged in the production, trading, distribution and marketing of natural gas, NGL and condensate products. This concentration of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Generally,

our customers' historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable; however, for the three months ended March 31, 2014 and 2013, no allowances on or write-offs of accounts receivable were recorded.

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The following table summarizes the percentage of revenue earned from those customers that accounted for 10% or more of the Partnership's consolidated revenue in the condensed consolidated statement of operations for the each of the periods presented below:

	Three months ended March 31,		
	2014	2013	
Customer A	30	% 30	%
Customer B	—	% 15	%
Customer C	15	% 12	%
Customer D	12	% 12	%
Other	43	% 31	%
Total	100	% 100	%

6. Derivatives

Commodity Derivatives

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. Those commodity hedge contracts may be in the form of swaps, puts and/or collars. 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. As of March 31, 2014, the aggregate notional volume of our commodity derivatives was 3.1 million gallons.

We enter into commodity contracts with multiple counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of March 31, 2014, we have not posted collateral with any counterparty. Our 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.

For accounting purposes, no derivative instruments were designated as hedging instruments and were instead accounted for under the mark-to-market method of accounting, with any changes in the fair value of the derivatives recorded in the condensed consolidated balance sheets and through earnings, rather than being deferred until the anticipated transactions affect earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices or interest rates.

Interest Rate Swap

We entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting a portion of our long-term variable rate debt into fixed rate debt. As of March 31, 2014, the notional amount of our interest rate swap was \$100.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral.

Weather Derivative

In the second quarter of 2013, we entered into a weather derivative to mitigate the impact of potential unfavorable weather to our operations under which we could receive payments totaling up to \$10.0 million in the event that a hurricane or hurricanes of certain strength pass through the area as identified in the derivative agreement. The weather derivative is being accounted for using the intrinsic value method, under which the fair value of the contract is zero and any amounts received are recognized as gains during the period received. The weather derivative was entered into with a single counterparty and we were not required to post collateral. We paid a premium of approximately \$1.1 million which is recorded in Risk management assets on the condensed consolidated balance sheet and is being

amortized to Direct operating expenses on a straight-line basis over the 1 year term of the contract. As of March 31, 2014, the unamortized amount of the risk management asset was approximately \$0.2 million. As of March 31, 2014 and December 31, 2013, the value associated with our commodity derivatives, interest rate swap instrument and weather derivative were recorded in our condensed consolidated balance sheets, under the captions as follows (in thousands):

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Balance Sheet Classification	Gross Risk Management Assets		Gross Risk Management Liabilities		Net Risk Management Assets (Liabilities)	
	March 31, 2014	December 31, 2013	March 31, 2014	December 31, 2013	March 31, 2014	December 31, 2013
Current	\$189	\$473	\$—	\$—	\$189	\$473
Noncurrent	—	—	—	—	—	—
Total assets	\$189	\$473	\$—	\$—	\$189	\$473
Current	\$55	\$27	\$(543)	\$(450)	\$(488)	\$(423)
Noncurrent	—	—	(75)	(101)	(75)	(101)
Total liabilities	\$55	\$27	\$(618)	\$(551)	\$(563)	\$(524)

For the three months ended March 31, 2014 and 2013, respectively, the realized and unrealized gains (losses) associated with our commodity derivatives, interest rate swap instrument and weather derivative were recorded in our condensed consolidated statements of operations, under the captions as follows (in thousands):

Statement of Operations Classification	Three months ended March 31, 2014	
	Realized	Unrealized
Loss on commodity derivatives, net	\$(102)	\$(28)
Interest expense	(104)	(11)
Direct operating expenses	(284)	—
Total	\$(490)	\$(39)
Gain (loss) on commodity derivatives, net	\$176	\$(481)

7. Fair Value Measurement

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include:

Level 1 – Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2 – Inputs include quoted prices for similar assets and liabilities in active markets that are either directly or indirectly observable; and

Level 3 – Inputs are unobservable and considered significant to fair value measurement.

A financial instrument's categorization within the fair value hierarchy is based upon 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 classification of assets and liabilities within the fair value hierarchy.

We believe the carrying amount of cash and cash equivalents approximates fair value because of the short-term maturity of these instruments. Our cash and cash equivalents would be classified as Level 1 under the fair value hierarchy.

The recorded value of the amounts outstanding under the credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates and the short-term nature of borrowings and repayments under the credit facility. Our existing revolving credit facility would be classified as Level 1 under the fair value hierarchy.

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

We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivatives contracts held. We recognize transfers between levels

at the end of the reporting period for which the transfer has occurred. There were no transfers out of Level 3 into Level 2 for the three months ended March 31, 2014 and 2013.

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Fair Value of Financial Instruments

The following table sets forth by level within the fair value hierarchy, our commodity derivative instruments and interest rate swap, included as part of Risk management assets and Risk management liabilities within the condensed consolidated balance sheet, that were measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013 (in thousands):

	Carrying Amount	Estimated Fair Value			Total
		Level 1	Level 2	Level 3	
Commodity derivative instruments, net					
March 31, 2014	\$(98) \$—	\$(98) \$—	\$(98
December 31, 2013	(70) —	(70) —	(70
Interest rate swap					
March 31, 2014	\$(465) \$—	\$(465) \$—	\$(465
December 31, 2013	(454) —	(454) —	(454

The premium paid to enter the weather derivative described in Note 6 "Derivatives" is included within Risk management assets on the balance sheet but is not included as part of the above table as it is recorded at amortized carrying cost, not fair value.

8. Property, Plant and Equipment

Property, plant and equipment, net, as of March 31, 2014 and December 31, 2013 were as follows (in thousands):

	Useful Life (in years)	March 31, 2014	December 31, 2013
Land	N/A	\$6,017	\$6,015
Construction in progress	N/A	6,978	6,443
Base gas	N/A	1,108	1,108
Buildings and improvements	4 to 40	5,358	5,109
Processing and treating plants	8 to 40	97,799	97,106
Pipelines	5 to 40	292,498	239,826
Compressors	4 to 20	11,822	11,793
Dock	20 to 40	7,954	7,942
Tanks, truck rack and piping	20 to 40	22,432	22,432
Equipment	8 to 20	8,076	6,293
Computer software	5	3,598	3,531
Total property, plant and equipment		463,640	407,598
Accumulated depreciation		(98,388) (95,088
Property, plant and equipment, net		\$365,252	\$312,510

Of the gross property, plant and equipment balances at March 31, 2014 and December 31, 2013, \$100.5 million and \$100.5 million, respectively, were related to AlaTenn, Midla and HPGT, our FERC regulated interstate and intrastate assets.

Capitalized interest was \$0.1 million and less than \$0.1 million for the three months ended March 31, 2014 and 2013, respectively.

Depreciation expense was \$6.5 million and \$5.7 million for the three months ended March 31, 2014 and 2013, respectively.

9. Debt Obligations

As of March 31, 2014, the Partnership's Credit Agreement (the "Credit Agreement") provides for a maximum borrowing equal to \$200.0 million subject to, among other restrictions, the requirement that our indebtedness not exceed 5.75 times adjusted consolidated EBITDA. We can elect to have loans under our credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 1.50% to 3.75% depending on our total leverage ratio

then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 2.50% to 4.75% depending on the total leverage ratio then in effect. We also paid a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

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Our obligations under the credit facility are secured by a first mortgage in favor of the lenders in our real property. Advances made under the credit facility are guaranteed on a senior unsecured basis by certain of our subsidiaries (“Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the new credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, August 1, 2016.

The credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are i) a total consolidated leverage ratio test (not to exceed 5.75 times) and ii) a minimum interest coverage ratio test (not less than 2.50).

For the three months ended March 31, 2014 and 2013, the weighted average interest rate on borrowings under our credit facility was approximately 4.40% and 4.34%, respectively.

As of March 31, 2014, our consolidated total leverage was 3.13 times, which was in compliance with the consolidated total leverage ratio test in our credit facility, and we had approximately \$125.7 million of outstanding borrowings under our credit facility and approximately \$69.0 million of available borrowing capacity.

Other debt

Other debt represents insurance premium financing in the original amount of \$2.5 million bearing interest at 3.95% per annum, which is repayable in equal monthly installments of approximately \$0.3 million through the third quarter of 2014.

Our outstanding borrowings at March 31, 2014 and December 31, 2013, respectively, were (in thousands):

	March 31, 2014	December 31, 2013
Revolving credit facility	\$125,650	\$130,735
Other debt	1,427	2,048
Total debt	127,077	132,783
Less: current portion	1,427	2,048
Long-term debt	\$125,650	\$130,735

At March 31, 2014 and December 31, 2013, letters of credit outstanding under the credit facility totaled \$5.4 million and \$4.8 million, respectively.

In connection with our credit facility and amendments thereto, we incurred \$6.6 million in debt issuance costs that are being amortized on a straight-line basis over the term of the credit facility.

10. Partners’ Capital and Convertible Preferred Units

Our capital accounts are comprised of approximately 1.3% general partner interest and 98.7% limited partner interests. Our limited partners have limited rights of ownership as provided for under our partnership agreement and the right to participate in our distributions. Our General Partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the IDRs that are non-voting limited partner rights held by our General Partner.

Series B Units

Effective January 31, 2014, the Partnership created and issued to its General Partner 1,168,225 Series B Units. The Series B Units participate in distributions of the Partnership along with common units, with such distributions being made in cash or as in-kind distributions at the election of the Partnership. The Series B Units are entitled to vote along with common unitholders and such units will automatically convert to common units two years after the issuance date. Proceeds from the issuance of the Series B Units were used to partially fund the Lavaca Acquisition.

Equity Offering

On January 29, 2014, the Partnership and certain of its affiliates entered into an underwriting agreement (the “Underwriting Agreement”) with Barclays Capital Inc. and UBS Securities LLC (the “Underwriters”), providing for the issuance and sale by the Partnership, and the purchase by the Underwriter, of 3,400,000 common units representing limited partner interests in the

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Partnership at a price to the public of \$26.75 per common unit. The Partnership used the net proceeds of \$86.9 million to fund a portion of the Lavaca Acquisition.

General Partner Units

In connection with our equity offering, we received proceeds of \$1.3 million from our General Partner as consideration for 49,678 additional partner general units.

Issuance and Exercise of Warrant

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

The numbers of units outstanding as of March 31, 2014 and December 31, 2013, respectively, were as follows (in thousands):

	March 31, 2014	December 31, 2013
Series A convertible preferred units	5,354	5,279
Series B convertible units	1,168	—
Limited partner common units	11,135	7,414
General partners units	235	185

Net Income (Loss) attributable to Limited Partner Units

Net income (loss) is allocated to the General Partner and the limited partners in accordance with their respective ownership percentages, after giving effect to contractual distributions on Series A preferred convertible units, declared distributions on the Series B Units, limited partner and to the general partner units, including incentive distribution rights. Basic and diluted net income (loss) per limited partner unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding limited partner units during the period.

We compute earnings per unit using the two-class method. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the General Partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the General Partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The two-class method does not impact our overall net income (loss) or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income (loss) per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the General Partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit. We have no dilutive securities, therefore basic and diluted net income per unit are the same. We determined basic and diluted net income (loss) per limited partner unit as follows, (in thousands, except per unit amounts):

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	Three months ended March 31,	
	2014	2013
Net income (loss) from continuing operations	\$577	\$(3,471)
Less: Net income attributable to noncontrolling interests	108	155
Net income (loss) from continuing operations attributable to the Partnership	469	(3,626)
Less:		
Contractual distributions on Series A Units	3,182	—
General partner's distribution	482	80
General partner's share in undistributed loss	(106) (152)
Net loss from continuing operations available to limited partners	(3,089) (3,554)
Net (loss) income from operations of disposal groups, net of tax, available to limited partners	(68) 72
Net loss available to limited partners	\$(3,157) \$(3,482)
Weighted average number of units used in computation of limited partners' net (loss) income per unit (basic and diluted)	9,846	9,167
Limited partners' net (loss) income per common unit		
Basic and diluted:		
Loss from continuing operations	\$(0.31) \$(0.39)
(Loss) income from discontinued operations	(0.01) 0.01
Net loss	\$(0.32) \$(0.38)

Distributions

We made distributions of \$6.7 million and \$4.0 million, inclusive of distributions of \$0.4 million and zero in respect of our General Partner's incentive distribution rights, in the three months ended March 31, 2014 and 2013, respectively. We depend on our credit facility for future capital needs and may use it to fund a portion of cash distributions to unitholders, as necessary, depending on the level of our operating cashflow.

For the Series A Unit distributions for the quarter ended as of March 31, 2014, we have accrued \$1.3 million for the cash portion of the distribution and \$1.8 million for the paid-in-kind Series A Units. The distributions will be made in the second quarter of 2014.

11. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. The board of directors of our General Partner provides a long-term incentive plan ("LTIP") for its employees, consultants and directors who perform services for it or its affiliates. At March 31, 2014 and December 31, 2013, 684,217 and 855,089 units, respectively, were available for future grant under the LTIP.

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

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

The following table summarizes our unit-based awards for each of the periods indicated, in units:

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	Three months ended March 31,	
	2014	2013
Outstanding at beginning of period	75,529	90,938
Granted	174,691	23,921
Forfeited	—	(2,427)
Vested	(24,933)	(10,483)
Outstanding at end of period	225,287	101,949
Fair value per unit	\$24.05 to \$26.71	\$13.36 to \$21.40

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our units at the grant date. Compensation costs related to these awards, including amortization, for the three months ended March 31, 2014 and 2013 were \$0.4 million and \$0.4 million, respectively, which are classified as equity compensation expense in the condensed consolidated statements of operations and the non-cash portion in partners' capital on the condensed consolidated balance sheets.

The total fair value of vested units at the time of vesting was \$0.6 million and \$0.2 million for the three months ended March 31, 2014 and 2013, respectively.

The total compensation cost related to unvested awards not yet recognized at March 31, 2014 and 2013 was \$4.1 million and \$1.3 million, respectively, and the weighted average period over which this cost is expected to be recognized as of March 31, 2014 is approximately 3.4 years.

12. Income Taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. However, one of our subsidiaries, Blackwater, is a taxable entity. Partnership income tax for the three months ended March 31, 2014 was a benefit of less than \$0.1 million, resulting in an effective tax rate of 1.9%.

The effective tax rate for the three months ended March 31, 2014, differs from the statutory rate primarily due to transactions between the Partnership and its taxable subsidiary that generate tax deductions for the the taxable subsidiary and are eliminated in the consolidation of Net income (loss) before income tax benefit.

13. Commitments and Contingencies

Legal proceedings

On September 5, 2013, HPIP, our General Partner and the Partnership were named as defendants in an action filed by AIM challenging the Equity Restructuring. AIM Midstream Holdings, LLC v. High Point Infrastructure Partners, LLC, American Midstream GP, LLC and American Midstream Partners, LP (Civil Action No. 8803-VCP) was filed in the Court of Chancery of the State of Delaware. Among claims against the other parties to the litigation, the action asserts a claim of tortious interference with contract against the Partnership and sought either rescission of the Partnership's equity restructuring agreement executed on August 9, 2013 or, in the alternative, monetary damages.

On February 5, 2014, we, HPIP and our General Partner entered into a settlement (the "Settlement") with AIM Midstream Holdings regarding the action filed in Delaware Chancery Court by AIM Midstream Holdings. Under the Settlement, among other things:

- HPIP and AIM Midstream Holdings amended the LLC Amendment to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP's sharing percentage thereafter is 95% and AIM Midstream Holdings's Sharing Percentage is 5%;
- HPIP transferred all of the 85.02% of our outstanding new IDRs held by HPIP to our General Partner such that our General Partner owns 100% of the outstanding new IDRs; and

· we issued to AIM Midstream Holdings a warrant to purchase up to 300,000 common units of the Partnership at an exercise price of \$0.01 per common unit, which Warrant, among other terms, i) was exercisable at any time on or after February 8, 2014 until the tenth anniversary of February 5, 2014, ii) contained cashless exercise provisions and iii) contains customary anti-dilution and other protections. The Warrant was exercised on February 21, 2014.

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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 pipeline and processing 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.

Commitments and contractual obligations

Future non-cancelable commitments related to certain contractual obligations as of March 31, 2014 are presented below (in thousands):

	Payments Due by Period						
	Total	2014	2015	2016	2017	2018	Thereafter
Operating leases and service contracts (a)	\$5,737	\$732	\$951	\$776	\$782	\$724	\$1,772
Asset retirement obligations	34,827	—	—	7,867	—	—	26,960
Total	\$40,564	\$732	\$951	\$8,643	\$782	\$724	\$28,732

(a) Operating leases and service contracts have been reduced by total minimum sublease rentals of \$0.5 million due in the future under non-cancelable subleases.

Total expenses related to operating leases, asset retirement obligations, land site leases and right-of-way agreements were (in thousands):

	Three months ended March 31,	
	2014	2013
Operating leases and service contracts	\$862	\$219
Asset retirement obligations	190	10
	\$1,052	\$229

14. Related-Party Transactions

Employees of our General Partner are assigned to work for us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our General Partner to American Midstream, LLC, which, in turn, charges the appropriate subsidiary. Our General Partner does not record any profit or margin for the administrative and operational services charged to us. During the three months ended March 31, 2014 and 2013, administrative and operational services expenses of \$5.0 million and \$2.7 million, respectively, were charged to us by our General Partner. For the three months ended March 31, 2014 and 2013, we incurred approximately \$0.5 million and \$0.3 million, respectively, of costs primarily associated with certain business development activities led by an affiliate of our General Partner. We expect to be reimbursed by this affiliate of our General Partner for the business development costs related to those projects.

15. Reporting Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Gathering and Processing, (2) Transmission and (3) Terminals.

Gathering and Processing

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

Transmission

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

Terminals

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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 crude oil, bunker fuel, distillates, chemicals and agricultural products.

These segments are monitored separately by management for performance and are consistent with 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 business of each segment.

The following tables set forth our segment information for the three months ended March 31, 2014 and 2013 (in thousands):

	Three months ended March 31, 2014			
	Gathering and Processing	Transmission	Terminals	Total
Revenue	\$47,236	\$25,129	\$3,614	\$75,979
Loss on commodity derivatives, net	(130)	—	—	(130)
Total revenue	47,106	25,129	3,614	75,849
Operating expenses:				
Purchases of natural gas, NGL's and condensate	36,824	14,100	—	50,924
Direct operating expenses	4,057	3,118	1,675	8,850
Selling, general and administrative expenses				5,593
Equity compensation expense				360
Depreciation, amortization and accretion expense				7,632
Total operating expenses				73,359
Loss on sale of assets, net				(21)
Interest expense				(1,903)
Income tax benefit				11
Loss from operations of disposal groups, net of tax				(69)
Net income				508
Less: Net income attributable to non-controlling interests				108
Net income attributable to the Partnership				\$400
Segment gross margin (a)	\$10,036	\$11,014	\$1,939	\$22,989

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	Three months ended March 31, 2013		
	Gathering and Processing	Transmission	Total
Revenue	\$ 45,068	\$ 14,639	\$ 59,707
Loss on commodity derivatives, net	(305) —	(305)
Total revenue	44,763	14,639	59,402
Operating expenses:			
Purchases of natural gas, NGL's and condensate	36,700	10,601	47,301
Direct operating expenses	3,404	1,399	4,803
Selling, general and administrative expenses			3,425
Equity compensation expense			388
Depreciation, amortization and accretion expense			5,646
Total operating expenses			61,563
Gain on involuntary conversion of property, plant and equipment			421
Interest expense			(1,731)
Income from operations of disposal groups, net of tax			73
Net loss			(3,398)
Less: Net income attributable to non-controlling interests			155
Net loss attributable to the Partnership			\$ (3,553)
Segment gross margin (a)	\$ 8,481	\$ 3,995	\$ 12,476

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

Asset information, including capital expenditures, by segment is not included in reports used by our management in their monitoring of performance and therefore is not disclosed.

16. Subsidiary Guarantors

The subsidiaries of the Partnership (the "Subsidiaries") are co-registrants with the Partnership, and the registration statement registers guarantees of debt securities by one or more of the Subsidiaries (other than American Midstream Finance Corporation, a 100% owned subsidiary of the Partnership whose sole purpose is to act as co-issuer of such debt securities). The financial position and operations of the co-issuer are minor and therefore have been included with the Parent's financial information. As of June 30, 2012, the Subsidiaries were 100% owned by the Partnership and any guarantees by the Subsidiaries will be full and unconditional. As of March 31, 2014, the Subsidiaries have an investment in the non-guarantor subsidiaries equal to a 92.2% undivided interest in its Chatom system. The Partnership has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to the Partnership. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by the Partnership, such guarantees will constitute joint and several obligations. None of the assets of the Partnership or the Subsidiaries represent restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X under the Securities Act of 1933, as amended. For purposes of the following condensed

consolidating financial information, the Partnership's investments in its Subsidiaries and the guarantor subsidiaries' investment in its 92.2% undivided interest in the Chatom system are presented in accordance with the equity method of accounting. The financial information may not necessarily be indicative of the financial position, results of operations, or cash flows had the subsidiary guarantors operated as independent entities. Condensed consolidating financial information for the Partnership, its combined guarantor subsidiaries and non-guarantor subsidiary as of March 31, 2014 and 2013, and for those three months ended is as follows (in thousands):

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Condensed Consolidating Balance Sheet

March 31, 2014

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Assets					
Current assets					
Cash and cash equivalents	\$1	\$2,021	\$ —	\$—	\$2,022
Accounts receivable	—	4,385	3,485	—	7,870
Unbilled revenue	—	20,707	4,193	—	24,900
Risk management assets	—	189	—	—	189
Other current assets	—	9,514	400	—	9,914
Current assets held for sale	—	1,582	—	—	1,582
Total current assets	1	38,398	8,078	—	46,477
Risk management assets, long-term	—	—	—	—	—
Property, plant and equipment, net	—	307,996	57,256	—	365,252
Note receivable	27,315	—	—	(27,315)	—
Goodwill	—	16,253	—	—	16,253
Intangible assets, net	—	50,692	—	—	50,692
Deferred tax asset	—	—	—	—	—
Other assets, net	—	8,093	726	—	8,819
Noncurrent assets held for sale, net	—	1,912	—	—	1,912
Investment in subsidiaries	255,005	58,310	—	(313,315)	—
Total assets	\$282,321	\$481,654	\$ 66,060	\$(340,630)	\$489,405
Liabilities, Equity and Partners' Capital					
Current liabilities					
Accounts payable	\$25	\$1,519	\$ 48	\$—	\$1,592
Accrued gas purchases	—	14,933	2,601	—	17,534
Accrued expenses and other current liabilities	1,339	14,613	17	—	15,969
Current portion of long-term debt	—	1,427	—	—	1,427
Risk management liabilities	—	488	—	—	488
Current liabilities held for sale	—	1,383	—	—	1,383
Total current liabilities	1,364	34,363	2,666	—	38,393
Risk management liabilities - long-term	—	75	—	—	75
Asset retirement obligations	—	34,352	475	—	34,827
Other liabilities	—	270	—	—	270
Long-term debt	—	152,965	—	(27,315)	125,650
Deferred tax liability	—	4,542	—	—	4,542
Noncurrent liabilities held for sale, net	—	82	—	—	82
Total liabilities	1,364	226,649	3,141	(27,315)	203,839
Convertible preferred units					
Series A convertible preferred units	96,654	—	—	—	96,654
Total partners' capital	184,303	255,005	58,310	(313,315)	184,303
Noncontrolling interests	—	—	4,609	—	4,609
Total equity and partners' capital	184,303	255,005	62,919	(313,315)	188,912
Total liabilities, equity and partners' capital	\$282,321	\$481,654	\$ 66,060	\$(340,630)	\$489,405

Table of ContentsCondensed Consolidating Balance Sheet
December 31, 2013

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Assets					
Current assets					
Cash and cash equivalents	\$1	\$392	\$ —	\$—	\$393
Accounts receivable	—	4,461	2,361	—	6,822
Unbilled revenue	—	17,325	4,680	—	22,005
Risk management assets	—	473	—	—	473
Other current assets	84	6,942	555	(84) 7,497
Current assets held for sale	—	1,268	—	—	1,268
Total current assets	85	30,861	7,596	(84) 38,458
Property, plant and equipment, net	—	254,465	58,045	—	312,510
Note receivable	27,315	—	—	(27,315) —
Goodwill	—	16,447	—	—	16,447
Intangible assets, net	—	3,682	—	—	3,682
Other assets, net	—	8,321	743	—	9,064
Noncurrent assets held for sale, net	—	1,914	—	—	1,914
Investment in subsidiaries	142,758	57,750	—	(200,508) —
Total assets	\$170,158	\$373,440	\$ 66,384	\$(227,907) \$382,075
Liabilities, Equity and Partners' Capital					
Current liabilities					
Accounts payable	\$30	\$2,902	\$ 329	\$—	\$3,261
Accrued gas purchases	—	13,290	3,104	—	16,394
Accrued expenses and other current liabilities	1,478	13,563	101	(84) 15,058
Current portion of long-term debt	—	2,048	—	—	2,048
Risk management liabilities	—	423	—	—	423
Current liabilities held for sale	—	1,106	—	—	1,106
Total current liabilities	1,508	33,332	3,534	(84) 38,290
Risk management liabilities - long-term	—	101	—	—	101
Asset retirement obligations	—	34,164	472	—	34,636
Other liabilities	—	191	—	—	191
Long-term debt	—	158,050	—	(27,315) 130,735
Deferred tax liability	—	4,749	—	—	4,749
Noncurrent liabilities held for sale, net	—	95	—	—	95
Total liabilities	1,508	230,682	4,006	(27,399) 208,797
Convertible preferred units					
Series A convertible preferred units	94,811	—	—	—	94,811
Total partners' capital	73,839	142,758	57,750	(200,508) 73,839
Noncontrolling interests	—	—	4,628	—	4,628
Total equity and partners' capital	73,839	142,758	62,378	(200,508) 78,467
Total liabilities, equity and partners' capital	\$170,158	\$373,440	\$ 66,384	\$(227,907) \$382,075

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Condensed Consolidating Statements of Operations

Three months ended March 31, 2014

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated	
Revenue	\$—	\$64,413	\$ 11,566	\$—	\$75,979	
Loss on commodity derivatives, net	—	(103) (27) —	(130)
Total revenue	—	64,310	11,539	—	75,849	
Operating expenses:						
Purchases of natural gas, NGLs and condensate	—	41,757	9,167	—	50,924	
Direct operating expenses	—	7,828	1,022	—	8,850	
Selling, general and administrative expenses	—	5,593	—	—	5,593	
Equity compensation expense	—	360	—	—	360	
Depreciation and accretion expense	—	7,212	420	—	7,632	
Total operating expenses	—	62,750	10,609	—	73,359	
Loss on sale of assets, net	—	(21) —	—	(21)
Operating income	—	1,539	930	—	2,469	
Earnings from consolidated affiliate	(181) 822	—	(641) —	
Interest income (expense)	581	(2,484) —	—	(1,903)
Net loss before income tax benefit	400	(123) 930	(641) 566	
Income tax benefit	—	11	—	—	11	
Net loss from continuing operations	400	(112) 930	(641) 577	
Loss from operations of disposal groups, net of tax	—	(69) —	—	(69)
Net income	400	(181) 930	(641) 508	
Net income attributable to noncontrolling interests	—	—	108	—	108	
Net loss attributable to the Partnership	\$400	\$(181) \$ 822	\$(641) \$400	

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Condensed Consolidating Statements of Operations					
Three months ended March 31, 2013					
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Revenue	\$—	\$48,022	\$ 13,648	\$(1,963) \$59,707
Loss on commodity derivatives, net	—	(305) —	—	(305)
Total revenue	—	47,717	13,648	(1,963) 59,402
Operating expenses:					
Purchases of natural gas, NGLs and condensate	—	38,346	10,918	(1,963) 47,301
Direct operating expenses	—	3,718	1,085	—	4,803
Selling, general and administrative expenses	—	3,425	—	—	3,425
Equity compensation expense	—	388	—	—	388
Depreciation and accretion expense	—	5,232	414	—	5,646
Total operating expenses	—	51,109	12,417	(1,963) 61,563
Gain on involuntary conversion of property, plant and equipment	—	421	—	—	421
Operating (loss) income	—	(2,971) 1,231	—	(1,740)
(Loss) earnings from consolidated affiliate	(3,553) 1,076	—	2,477	—
Interest expense	—	(1,731) —	—	(1,731)
Net (loss) income from continuing operations	(3,553) (3,626) 1,231	2,477	(3,471)
Income from operations of disposal groups, net of tax	—	73	—	—	73
Net (loss) income	(3,553) (3,553) 1,231	2,477	(3,398)
Net income attributable to noncontrolling interests	—	—	155	—	155
Net (loss) income attributable to the Partnership	\$(3,553) \$(3,553) \$ 1,076	\$2,477	\$(3,553)

Table of ContentsCondensed Consolidating Statements of Comprehensive Income
Three months ended March 31, 2014

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Net income	\$400	\$(181) \$ 930	\$(641) \$508
Unrealized gain on post retirement benefit plan assets and liabilities	36	36	—	(36) 36
Comprehensive income	436	(145) 930	(677) 544
Less: Comprehensive income attributable to noncontrolling interests	—	—	108	—	108
Comprehensive income attributable to the Partnership	\$436	\$(145) \$ 822	\$(677) \$436

Condensed Consolidating Statements of Comprehensive Income
Three months ended March 31, 2013

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated	
Net (loss) income	\$(3,553) \$(3,553) \$ 1,231	\$2,477	\$(3,398)
Unrealized loss on post retirement benefit plan assets and liabilities	(13) (13) —	13	(13)
Comprehensive (loss) income	(3,566) (3,566) 1,231	2,490	(3,411)
Less: Comprehensive income attributable to noncontrolling interests	—	—	155	—	155	
Comprehensive (loss) income attributable to the Partnership	\$(3,566) \$(3,566) \$ 1,076	\$2,490	\$(3,566)

Table of ContentsCondensed Consolidating Statements of Cash Flows
Three months ended March 31, 2014

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Net cash provided by operating activities	\$—	\$3,534	\$ 20	\$—	\$3,554
Cash flows from investing activities					
Cost of acquisitions, net of cash acquired	—	(110,909) —	—	(110,909)
Additions to property, plant and equipment	—	(4,297) 369	—	(3,928)
Proceeds from disposals of property, plant and equipment	—	6,135	—	—	6,135
Net contributions from affiliates	5,379	—	—	(5,379) —
Net distributions to affiliates	(118,202) —	—	118,202	—
Net cash (used in) provided by financing activities	(112,823) (109,071) 369	112,823	(108,702)
Cash flows from financing activities					
Net contributions from affiliates	—	118,202	—	(118,202) —
Net distributions to affiliates	—	(5,088) (291) 5,379	—
Proceeds from issuance of common units to public, net of offering costs	86,926	—	—	—	86,926
Unit holder contributions	1,276	—	—	—	1,276
Unit holder distributions	(5,379) —	—	—	(5,379)
Issuance of Series B Units	30,000	—	—	—	30,000
Acquisition of noncontrolling interest	—	(8) —	—	(8)
Net distributions to noncontrolling interest owners	—	—	(98) —	(98)
LTIP tax netting unit repurchase	—	(90) —	—	(90)
Deferred debt issuance costs	—	(144) —	—	(144)
Payments on other debt	—	(791) —	—	(791)
Borrowings on other debt	—	170	—	—	170
Payments on long-term debt	—	(49,771) —	—	(49,771)
Borrowings on long-term debt	—	44,686	—	—	44,686
Net cash provided by (used in) financing activities	112,823	107,166	(389) (112,823) 106,777
Net increase in cash and cash equivalents	—	1,629	—	—	1,629
Cash and cash equivalents					
Beginning of period	1	392	—	—	393
End of period	\$ 1	\$2,021	\$—	\$—	\$2,022
Supplemental cash flow information					
Interest payments, net	\$—	\$1,781	\$—	\$—	\$1,781
Supplemental non-cash information					
Decrease in accrued property, plant and equipment	\$—	\$(1,474) \$—	\$—	\$(1,474)

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Condensed Consolidating Statements of Cash Flows					
Three months ended March 31, 2013					
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	\$—	\$(127) \$ 1,230	\$—	\$1,103
Cash flows from investing activities					
Additions to property, plant and equipment	—	(7,995) (57) —	(8,052)
Insurance proceeds from involuntary conversion of property, plant and equipment	—	560	—	—	560
Net contributions from affiliates	4,044	—	—	(4,044) —
Net distributions to affiliates	—	—	—	—	—
Net cash provided by (used in) financing activities	4,044	(7,435) (57) (4,044) (7,492)
Cash flows from financing activities					
Net contributions from affiliates	—	—	—	—	—
Net distributions to affiliates	—	(3,081) (963) 4,044	—
Unit holder contributions	—	—	—	—	—
Unit holder distributions	(4,044) —	—	—	(4,044)
Net distributions to noncontrolling interest owners	—	—	(210) —	(210)
LTIP tax netting unit repurchase	—	(74) —	—	(74)
Deferred debt issuance costs	—	(912) —	—	(912)
Payments on other debt	—	(358) —	—	(358)
Borrowings on other debt	—	1,476	—	—	1,476
Payments on long-term debt	—	(17,585) —	—	(17,585)
Borrowings on long-term debt	—	27,565	—	—	27,565
Net cash (used in) provided by financing activities	(4,044) 7,031	(1,173) 4,044	5,858
Net decrease in cash and cash equivalents	—	(531) —	—	(531)
Cash and cash equivalents					
Beginning of period	1	575	—	—	576
End of period	\$1	\$44	\$—	\$—	\$45
Supplemental cash flow information					
Interest payments, net	\$—	\$1,487	\$—	\$—	\$1,487
Supplemental non-cash information					
Decrease in accrued property, plant and equipment	\$—	\$(3,977) \$—	\$—	\$(3,977)

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17. Subsequent Events

Distribution

On April 25, 2014, we announced a distribution of \$0.4625 per unit for the quarter ended March 31, 2014, or \$1.85 per unit on an annualized basis, payable on May 15, 2014 to unitholders of record on May 8, 2014. Holders of our Series B Units will participate pro rata in this distribution. We will exercise our right to pay the holders of our Series B Units in Series B Units rather than cash.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report and the audited consolidated financial statements and notes thereto and management’s discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 2013 included in i) our Annual Report on Form 10-K (“Annual Report”) that was filed with the SEC on March 11, 2014 and ii) our Annual Report on Form 10-K/A that was filed with the Securities and Exchange Commission (“SEC”) on May 12, 2014 which updated portions of our annual report. This discussion contains forward-looking statements that reflect management’s current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption “Cautionary Statement Regarding Forward-Looking Statements.”

Cautionary Statement About Forward-Looking Statements

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in “Item 1A. Risk Factors” and elsewhere in this Quarterly Report, the Annual Report and the following:

- our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services, including storage services in our Terminals segment;
- 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;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems;
- the demand for NGL products by the petrochemical, refining or other industries;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects and the successful integration and future performance of such assets;
- our ability to hire as well as retain qualified personnel to execute our business strategy;

•volatility in the price of our common units;
•security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise
•impacting, our facilities and systems;
•our ability to timely and successfully integrate our current and future acquisitions, including the realization of all
•anticipated benefits of any such transaction, which otherwise could negatively impact our future financial
•performance; and
•general economic, market and business conditions.

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 other risks and uncertainties that could cause actual results to differ materially from such

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forward-looking statements are more fully described in “Item 1A. Risk Factors” and elsewhere in this Quarterly Report and our Annual Report. The forward-looking statements in this report speak as of the filing date of this report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

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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, fractionating and transporting natural gas through our ownership and operation of eleven gathering systems, two processing facilities, one fractionation facility, four terminal sites, three interstate pipelines and five intrastate pipelines. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Recently, we became an owner, developer and operator of petroleum, agricultural, and chemical liquid terminal storage facilities. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas and NGL markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 2,300 miles of pipelines that gather and transport approximately 1 Bcf/d of natural gas and operate approximately 1.3 million barrels of above-ground storage capacity across four marine terminal sites.

Significant financial highlights during the three months ended March 31, 2014, include the following:

We completed the Lavaca Acquisition, which consisted of approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The consideration for the Lavaca Acquisition was financed with a portion of the net proceeds from the Partnership's January 2014 equity offering of \$86.9 million and the proceeds from the issuance to our General Partner of 1,168,225 Series B Units representing Series B limited partnership interests in the Partnership;

We completed the Williams Pipeline Acquisition for \$6.5 million, consisting of natural gas pipeline facilities that are contiguous to, and connect with, our High Point System in offshore Louisiana;

We distributed \$6.7 million to our unitholders, or \$0.4525 per unit, during the three months ended March 31, 2014; and

For the three months ended March 31, 2014, gross margin increased to \$23.0 million, or an increase of 84.3%, compared to the same period in 2013.

Significant operational highlights during the three months ended March 31, 2014, include the following:

Throughput attributable to the Partnership totaled 1,148.3 MMcf/d for the first quarter of 2014 representing a 67.1% increase compared to the same period in 2013;

Average gross NGL production totaled 38.6 Mgal/d for the first quarter of 2014 representing a 28.4% decrease compared to the same period in 2013; and

Average condensate production totaled 42.2 Mgal/d for the first quarter of 2014, a 4.5% decrease compared to the first quarter of 2013.

Recent Developments

On April 2, 2014, we announced our filing to request with the FERC to abandon use of its Midla "Mainline" pipeline in order to ensure the safety of people and property along its route. In our application, we explained that, due to original pipeline construction techniques, modern tools cannot be used to find or predict leaks. As a result of the filing, certain of Midla's customers objected to higher rates they may be required to pay if new facilities are constructed. We believe that an expedited technical conference will clarify the facts, and lay the groundwork for a substantive decision from the FERC clarifying the law and allowing the parties to find a long-term solution.

Subsequent Events

Distribution

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On April 25, 2014, we announced a distribution of \$0.4625 per unit for the quarter ended March 31, 2014, or \$1.85 per unit on an annualized basis, payable on May 15, 2014 to unitholders of record on May 8, 2014. Holders of our Series B Units will participate pro rata in this distribution. We will exercise our right to pay the holders of our Series B Units in Series B Units rather than cash.

Our Operations

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

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

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

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

Gathering and Processing Segment

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

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

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. By entering into back-to-back purchases and sales of natural gas, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

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

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

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

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in volumes and, thus, a decrease in our fee-based and fixed-margin gross

margin. These arrangements provide stable cash flows but minimal, if any, upside in higher commodity-price environments. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure

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to commodity price risk through our hedging program. Please read “ —Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.”

Transmission Segment

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

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

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

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

Terminals Segment

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

How We Evaluate Our Operations

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

Throughput Volumes

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

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

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

Gross Margin and Segment Gross Margin

Gross margin and segment gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as revenue generated from gathering and processing operations less the cost of natural gas, NGLs and condensate purchased. Revenue includes revenue generated from fixed fees associated with the gathering and treating

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

We define segment gross margin in our Transmission segment as revenue generated from firm and interruptible transportation agreements and fixed-margin arrangements, plus other related fees, less the cost of natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

We define segment gross margin in our Terminals segment as revenue generated from fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers less direct operating expense which includes direct labor, general materials and supplies and direct overhead.

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

Direct Operating Expenses

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

Adjusted EBITDA

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

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

We define adjusted EBITDA as net income, plus interest expense, income tax expense, depreciation expense, certain non-cash charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts and selected charges that are unusual or nonrecurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, amortization of commodity put purchase costs, and selected gains that are unusual or nonrecurring. The GAAP measure most directly comparable to adjusted EBITDA is net income.

Note About Non-GAAP Financial Measures

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

You should not consider any of gross margin or adjusted EBITDA in isolation or as a substitute for or more meaningful than analysis of our results as reported under GAAP. Gross margin and adjusted EBITDA may be defined differently by other companies in our industry. Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The following tables reconcile the non-GAAP financial measures of gross margin and adjusted EBITDA used by management to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for the three months ended March 31, 2014 and 2013 (in thousands):

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	Three months ended March 31,	
	2014	2013
Reconciliation of gross margin to Net income (loss) attributable to the Partnership:		
Gathering and processing segment gross margin	\$ 10,036	\$ 8,481
Transmission segment gross margin	11,014	3,995
Terminals segment gross margin	1,939	—
Total gross margin	22,989	12,476
Plus:		
Loss on commodity derivatives	(130) (305
Less:		
Direct operating expenses (a)	7,175	4,803
Selling, general and administrative expenses	5,593	3,425
Equity compensation expense	360	388
Depreciation, amortization and accretion expense	7,632	5,646
Gain on involuntary conversion of property, plant and equipment	—	(421
Loss on sale of assets	21	—
Interest expense	1,903	1,731
Other, net (b)	(391) 70
Income tax benefit	(11) —
Income (loss) from operations of disposal groups, net of tax	69	(73
Net income attributable to noncontrolling interest	108	155
Net income (loss) attributable to the Partnership	\$ 400	\$ (3,553

- Direct operating expenses includes Gathering and Processing segment direct operating expenses of \$4.1 million and Transmission segment direct operating expenses of \$3.1 million for the three months ended March 31, 2014.
- (a) Direct operating expenses related to our Terminals segment of \$1.7 million are included within the calculation of Terminals segment gross margin.
- (b) Other, net includes realized loss (gain) on commodity derivatives of \$0.1 million and \$(0.2) million and COMA income of \$0.3 million and \$0.1 million for the three months ended March 31, 2014 and 2013, respectively.

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	Three months ended March 31,	
	2014	2013
Reconciliation of Net income (loss) attributable to the Partnership to Adjusted EBITDA		
Net income (loss) attributable to the Partnership	\$ 400	\$(3,553)
Add:		
Depreciation, amortization and accretion expense	7,632	5,646
Interest expense	1,493	1,731
Debt issuance costs	144	912
Unrealized loss on derivatives, net	39	481
Non-cash equity compensation expense	360	388
Transaction expenses	812	342
Income tax benefit	(26) —
Deduct:		
COMA income	289	106
Straight-line amortization of put costs (a)	—	27
OPEB plan net periodic benefit	11	18
Gain on involuntary conversion of property, plant and equipment	—	421
Loss on sale of assets, net	(43) —
Adjusted EBITDA	\$ 10,597	\$ 5,375

(a) Amounts noted represent the straight-line amortization of the cost of commodity put contracts over the life of the contract.

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed under the caption “Management’s Discussion and Analysis of Financial Condition and Results of Operations — General Trends and Outlook” in our Annual Report.

Results of Operations — Combined Overview

For the three months ended March 31, 2014, gross margin increased to \$23.0 million, or an increase of 84.3%, as compared to the same period in 2013. For the three months ended March 31, 2014, the increase in gross margin was largely a result of: i) an increase in gross margin in our Transmission segment of \$7.0 million primarily as a result of incremental revenue associated with our High Point System of \$7.0 million; ii) incremental gross margin in our Terminals segment of \$1.9 million, and iii) an increase in gross margin in our Gathering and Processing segment of \$1.6 million due to increased throughput volumes of 39.5 MMcf/d primarily associated with our newly acquired Lavaca System in the Gathering and Processing segment.

We distributed \$4.9 million to holders of our common units, or \$0.4525 per unit, during the three months ended March 31, 2014.

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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 March 31,	
	2014	2013
Statement of Operations Data:		
Revenue	\$75,979	\$59,707
Loss on commodity derivatives, net	(130) (305
Total revenue	75,849	59,402
Operating expenses:		
Purchases of natural gas, NGLs and condensate	50,924	47,301
Direct operating expenses	8,850	4,803
Selling, general and administrative expenses	5,593	3,425
Equity compensation expense (a)	360	388
Depreciation, amortization and accretion expense	7,632	5,646
Total operating expenses	73,359	61,563
Gain on involuntary conversion of property, plant and equipment	—	421
Loss on sale of assets, net	(21) —
Operating income (loss)	2,469	(1,740
Other expense:		
Interest expense	(1,903) (1,731
Net income (loss) before income tax benefit	566	(3,471
Income tax benefit	11	—
Net income (loss) from continuing operations	577	(3,471
Discontinued operations:		
(Loss) income from operations of disposal groups, net of tax	(69) 73
Net income (loss)	508	(3,398
Net income attributable to noncontrolling interests	108	155
Net income (loss) attributable to the Partnership	\$400	\$(3,553
Other Financial Data:		
Gross margin (b)	\$22,989	\$12,476
Adjusted EBITDA (b)	\$10,597	\$5,375

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

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

Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

Revenue. Our revenue for the three months ended March 31, 2014 was \$76.0 million compared to \$59.7 million for the three months ended March 31, 2013. This increase of \$16.3 million was primarily due to the following: Natural gas revenues increased \$5.6 million as a result of i) higher realized natural gas prices of \$5.66/Mcf, an increase of \$1.96/Mcf, or 53.0%, period over period, offset by ii) decreased natural gas sales volumes 14.2% period over period;

Condensate revenues decreased \$1.6 million as a result of lower condensate production of 2.0 Mgal/d due to lower realized condensate prices of \$2.22/gal, a decrease of \$0.17/gal period over period, partially offset by incremental volumes at Lavaca;

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NGL revenues decreased \$2.1 million as a result of lower gross NGL production volumes of 18.4 Mgal/d from our Gathering and Processing segment offset by higher realized NGL prices of \$1.07/gal, an increase of \$0.19/gal period over period;

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Transmission revenues from the transportation of natural gas increased \$9.6 million primarily as a result of incremental revenue of \$7.0 million associated with our High Point System; and incremental Terminals segment revenue of \$3.6 million.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended March 31, 2014 were \$50.9 million compared to \$47.3 million for the three months ended March 31, 2013. This increase of \$3.6 million was primarily due to higher purchase costs associated with natural gas and NGLs due to higher realized natural gas and NGL prices, partially offset by lower natural gas purchase volumes related to POP contracts associated with owned processing plants in our Gathering and Processing segment and lower realized condensate prices and volumes associated with our POP contracts.

Gross Margin. Gross margin for the three months ended March 31, 2014 was \$23.0 million compared to \$12.5 million for the three months ended March 31, 2013. This increase of \$10.5 million was primarily due to: i) an increase in gross margin in our Transmission segment of \$7.0 million as a result of incremental revenue associated with our High Point System of \$7.0 million; ii) incremental gross margin of \$1.9 million in our Terminals segment and; iii) an increase in gross margin in our Gathering and Processing segment of \$1.6 million due to higher natural gas throughput volumes of 39.5 MMcf/d, or 16.1%, primarily attributable to the newly acquired Lavaca System.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2014 were \$8.9 million compared to \$4.8 million in the three months ended March 31, 2013. This increase of \$4.1 million was primarily due to: i) \$2.1 million of incremental direct operating expenses associated with the High Point System; ii) \$1.7 million of incremental expenses associated with our Terminals segment; iii) \$0.7 million of incremental costs associated with Lavaca; iv) \$0.5 million associated with additional aerial inspections of our Transmission segment; and v) \$0.4 million of increased costs associated with our property and casualty insurance.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the three months ended March 31, 2014 were \$5.6 million compared to \$3.4 million for the three months ended March 31, 2013. This increase of \$2.2 million was primarily due to i) higher salaries and wages of \$0.9 million due to increased staffing resulting from our acquisitions and ii) increased transaction expenses of \$0.5 million and higher consulting and advisory services of \$0.3 million related to the Lavaca Acquisition.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended March 31, 2014 was \$7.6 million compared to \$5.6 million for the three months ended March 31, 2013. This increase of \$2.0 million was due to depreciation associated with i) the contributed assets of the High Point System and Terminals segment; ii) amortization of intangible assets; and iii) other capital projects placed into service during the period.

Interest Expense. Interest expense for the three months ended March 31, 2014 was \$1.9 million compared to \$1.7 million for the three months ended March 31, 2013. This increase of \$0.2 million was primarily due to the increase in borrowings under our credit facility combined with an increase to our weighted average interest rate of 0.06% as a result of the Fourth Amendment to our Credit Agreement.

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Results of Operations — Segment Results

The table below contains key segment performance indicators related to our segment results of operations (in thousands except operating and pricing data):

	Three months ended March 31,	
	2014	2013
Segment Financial and Operating Data:		
Gathering and Processing segment		
Financial data:		
Revenue	\$47,236	\$45,068
Loss on commodity derivatives	(130)	(305)
Total revenue	47,106	44,763
Purchases of natural gas, NGLs and condensate	36,824	36,700
Direct operating expenses	(4,057)	(3,404)
Other financial data:		
Segment gross margin	\$10,036	\$8,481
Operating data:		
Average throughput (MMcf/d)	284.1	244.6
Average plant inlet volume (MMcf/d) (a) (b)	87.6	97.1
Average gross NGL production (Mgal/d) (a) (c)	38.6	53.9
Average gross condensate production (Mgal/d) (a)	42.2	44.2
Average realized prices:		
Natural gas (\$/Mcf)	\$5.66	\$3.70
NGLs (\$/gal)	\$1.07	\$0.88
Condensate (\$/gal)	\$2.22	\$2.39
Transmission segment		
Financial data:		
Total revenue	\$25,129	\$14,639
Purchases of natural gas, NGLs and condensate	14,100	10,601
Direct operating expenses	(3,118)	(1,399)
Other financial data:		
Segment gross margin	\$11,014	\$3,995
Operating data:		
Average throughput (MMcf/d)	864.2	442.6
Average firm transportation - capacity reservation (MMcf/d)	631.7	777.7
Average interruptible transportation - throughput (MMcf/d)	522.8	129.1
Terminals segment		
Financial data:		
Total revenue	\$3,614	\$—
Direct operating expenses	1,675	—
Other financial data:		
Segment gross margin	\$1,939	\$—
Operating data:		
Storage Utilization	100	% —

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

(b) Includes gross plant inlet volume associated with our interest in the Burns Point processing plant.

(c) Includes net NGL production associated with our interest in the Burns Point processing plant.

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Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

Gathering and Processing Segment

Revenue. Segment total revenue in the three months ended March 31, 2014 was \$47.1 million compared to \$44.8 million in the three months ended March 31, 2013. This increase of \$2.3 million was primarily due to the following:

- An increase in realized natural gas prices of 53.0% and an increase in realized NGL prices of 21.6% offset by lower realized condensate prices of 7.1% period over period as a result of variable commodity prices;

- Increased average natural gas throughput volumes by 39.5 MMcf/d, or 16.1%, period over period primarily as a result of incremental natural gas throughput volumes of 32.8 MMcf/d at our Lavaca System; offset by

- Lower average gross NGL production amounting to 15.3 Mgal/d, or a net decrease of 28.4% period over period, primarily as a result of our reduced production of 14.4 Mgal/d on our Bazor Ridge System;

- Lower average gross condensate production amounting to 2.0 Mgal/d, or a decrease of 4.5% period over period, as a result of our decreased production at our Chatom System; and

- A decrease in realized gains of \$0.3 million period over period on our commodity derivatives which was comprised of financial swaps, collars and option contracts which were used to mitigate commodity price risk.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the three months ended March 31, 2014 were \$36.8 million compared to \$36.7 million for the three months ended March 31, 2013. This increase of \$0.1 million was primarily due to higher purchase costs associated with natural gas and NGLs due to higher realized natural gas volumes and NGL prices, higher natural gas purchase volumes related to POP contracts associated with owned processing plants, offset by lower realized condensate prices and volumes.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2014 was \$10.0 million compared to \$8.5 million for the three months ended March 31, 2013. This increase of \$1.5 million was primarily due to the following:

- Incremental gross margin of \$2.3 million at our Lavaca System; offset by

- Lower gross margin of \$0.8 million on our Gloria System due to lower average gross NGL production associated with our elective processing agreement;

- Lower segment gross margin of \$0.4 million primarily associated with lower condensate production on our Chatom System; and

- A decrease in realized gains of \$0.3 million period over period on our commodity derivatives which was comprised of financial swaps, collars and option contracts which were used to mitigate commodity price risk.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2014 were \$4.1 million compared to \$3.4 million for the three months ended March 31, 2013. This increase of \$0.7 million was primarily due to the incremental operating costs associated with salaries and wages of our newly acquired Lavaca System.

Transmission Segment

Revenue. Segment total revenue for the three months ended March 31, 2014 was \$25.1 million compared to \$14.6 million for the three months ended March 31, 2013. This increase of \$10.5 million in segment revenue was primarily due to:

- Total natural gas throughput volumes on our transmission systems were 864.2 MMcf/d for the three months ended March 31, 2014 compared to 442.6 MMcf/d for the three months ended March 31, 2013 representing a 95.3% increase period over period, primarily due to the contribution of the High Point System amounting to \$7.0 million; and

- Higher realized natural gas prices on our fixed margin contracts of \$1.63/Mcf amounting to an increase of \$3.6 million.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended March 31, 2014 were \$14.1 million compared to \$10.6 million for the three months ended March 31, 2013.

This increase of \$3.5 million was primarily due to higher realized natural gas prices, which resulted in higher natural gas purchase costs associated with our fixed margin agreements on MLGT and Midla amounting to \$3.5 million.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2014 was \$11.0 million compared to \$4.0 million for the three months ended March 31, 2013. This increase of \$7.0 million was primarily due to incremental revenue associated with our High Point System of \$7.0 million.

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Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2014 were \$3.1 million compared to \$1.4 million for the three months ended March 31, 2013. This increase of \$1.7 million is primarily due to the incremental expense of our High Point System.

Terminals Segment

The Blackwater Acquisition represented a transaction between entities under common control and a change in reporting entity. Therefore we have accounted for Blackwater and our Terminals segment as if the transfer occurred as of April 15, 2013.

Revenue. Segment total revenue for the three months ended March 31, 2014 was \$3.6 million which consisted of fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2014 were \$1.7 million which consisted of direct labor, general materials and supplies and direct overhead.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2014 was \$1.9 million which is defined as segment total revenue less direct operating expense.

Liquidity and Capital Resources

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

The principal indicators of our available liquidity at March 31, 2014, were our cash on hand and availability under our credit facility. As of March 31, 2014, our available liquidity was \$71.0 million, comprised of cash on hand of \$2.0 million and \$69.0 million available under our credit facility. As of May 8, 2014, our available liquidity was \$69.2 million. We believe that cash generated from operating cash flows and liquidity will be sufficient to meet our short-term working capital requirements, medium-term capital expenditure requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, issuing equity and additional debt financing; in addition, we would reduce spending in certain areas, such as capital expenditures, as necessary.

In January 2014, we issued 3,400,000 common units at a price to the public of \$26.75 per unit. We received proceeds of \$86.9 million, net of offering costs.

Changes in natural gas, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A in our annual report, "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 are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Our Credit Facility

We are required to comply with certain financial covenants and ratios in our credit facility. As of March 31, 2014, our consolidated total leverage was 3.13 times, which was in compliance with the consolidated total leverage ratio test in accordance with the leverage covenants as modified in the Fifth Amendment to the credit facility executed on

December 17, 2013. As of March 31, 2014, we had approximately \$125.7 million of outstanding borrowings and approximately \$69.0 million of available borrowing capacity.

Working Capital

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Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital was \$8.1 million at March 31, 2014.

Cash Flows

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

	Three months ended March 31,	
	2014	2013
Net cash provided by (used in):		
Operating activities	\$3,554	\$1,103
Investing activities	(108,702) (7,492
Financing activities	106,777	5,858

Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

Operating Activities. Net cash provided by operating activities was \$3.6 million for the three months ended March 31, 2014 compared to \$1.1 million for the three months ended March 31, 2013. Net cash provided by operating activities for the three months ended March 31, 2014 increased period over period primarily due to i) increased gross margin of \$10.5 million, partially offset by ii) \$2.1 million of additional direct operating expenses associated with the High Point System, iii) \$0.4 million of additional costs associated with our property and casualty insurance and increased salaries of \$0.9 million, iv) \$0.5 million and \$0.4 million of increased transaction costs and interest payments, respectively and v) a decrease in proceeds received from the settlement of risk management assets and liabilities of \$0.3 million.

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

Investing Activities. Net cash used in investing activities was \$108.7 million for the three months ended March 31, 2014 compared to \$7.5 million for the three months ended March 31, 2013. Cash used in investing activities for the three months ended March 31, 2014 increased period over period primarily due to i) incremental payments of \$110.9 million used to fund the acquisition of the Lavaca and Williams Pipeline assets, partially offset by ii) a \$4.1 million decrease in capital expenditures and iii) \$6.1 million of proceeds related to the divestiture of the Madison assets.

Financing Activities. Net cash provided by financing activities was \$106.8 million for the three months ended March 31, 2014 compared to \$5.9 million for the three months ended March 31, 2013. Cash provided by financing activities for the three months ended March 31, 2014 increased period over period primarily due to i) incremental proceeds from the issuance of common units to the public of \$86.9 million and ii) the issuance of Series B Units of \$30.0 million, partially offset by iii) a decrease of \$15.1 million in net borrowings from our credit facility as result of proceeds received from equity offerings.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Capital Requirements

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

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maintenance capital expenditures, which are cash expenditures made to maintain our long-term operating income or operating capacity (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets); or expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

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Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the three months ended March 31, 2014, capital expenditures totaled \$3.9 million including growth capital expenditures of \$1.8 million, maintenance capital expenditures of \$2.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of \$0.1 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our partnership agreement.

Integrity Management

Certain operating assets require an ongoing integrity management program under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our total program addresses approximately 91 high consequence areas that require on-going testing pursuant to DOT regulations. Over the course of the seven-year cycle, we expect to incur approximately \$4.5 million in integrity management testing expenses.

Distributions

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

On April 25, 2014, we announced a distribution of \$0.4625 per unit for the quarter ended March 31, 2014, or \$1.85 per unit on an annualized basis, payable on May 15, 2014 to unitholders of record on May 8, 2014. Holders of our Series B Units will participate pro rata in this distribution. We will exercise our right to pay the holders of our Series B Units in Series B Units rather than cash.

Contractual Obligations

The table below summarizes our obligations and other commitments as of March 31, 2014 (in thousands):

	Payments Due by Period						
	Total	2014	2015	2016	2017	2018	Thereafter
Operating leases and service contracts (a)	\$5,737	\$732	\$951	\$776	\$782	\$724	\$1,772
Asset retirement obligations	34,827	—	—	7,867	—	—	26,960
Total	\$40,564	\$732	\$951	\$8,643	\$782	\$724	\$28,732

(a) Operating leases and service contracts have been reduced by total minimum sublease rentals of \$0.5 million due in the future under non-cancelable subleases.

Critical Accounting Policies

There were no changes to our significant accounting policies from those disclosed in the Annual Report.

Recent Accounting Pronouncements

In July 2013, the FASB issued ASC No. 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a consensus of the FASB Emerging Issues Task Force). This guidance was issued related to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The updated guidance requires an entity to net its unrecognized tax benefits against the deferred tax assets for all same jurisdiction net operating loss carryforward, a similar tax loss, or tax credit carryforwards. A gross presentation will be required only if such carryforwards are not available or would not be used by the entity to settle any additional income taxes resulting from disallowance of the uncertain tax position. The update was effective for the Partnership effective January 1, 2014 and did not have a material impact on its condensed consolidated financial statements.

In April 2014, the FASB issued ASC No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance amends the definition of discontinued operations to include components of an entity that have been disposed of, meet the criteria to be classified as held-for-sale, or has been abandoned/spun-off; and represents a strategic shift that has, or will have, a major effect on an entity's operations and financial results. The update applies to disposals and classifications

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as held-for-sale that occur after the effective date. The update is effective for all periods beginning after December 15, 2014 and is not expected to have a material impact on the Partnership.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures about Market Risk included in the Annual Report. We are exposed to market risk on our open derivative contracts of non-performance by our counterparties. We do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings. We did not post collateral under any of these contracts, as they are secured under our 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 6 "Derivatives" for further details. During 2013 and 2014, we entered into additional commodity contracts with existing counterparties to hedge our 2014 exposure to commodity prices. As of March 31, 2014, we have hedged approximately 13% of our expected exposure to NGL prices and 33% of our expected exposure to oil prices through the end of 2014.

The table below sets forth certain information regarding the financial instruments used to hedge of commodity price risk as of March 31, 2014:

Commodity	Instrument	Volumes (a)	Weighted Average Price	Period	Fair value at March 31, 2014 (in thousands)
NGLs (gal)	Swaps	(1,620,000)	\$1.07	Apr 2014 - Dec 2014	(9)
Oil (Bbl)	Collars (b)	(36,000)	\$98.90	Apr 2014 - Sep 2014	(89)
					\$(98)

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

(b) Collars contain weighted average price for floors and caps of \$96.50 and \$101.30, respectively.

Interest Rate Risk

During the three months ended March 31, 2014, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. During the second quarter of 2013, we entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting the cash flows related to \$100.0 million of our long-term variable rate debt into fixed rate cash flows.

The 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. 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 \$0.3 million for the three months ended March 31, 2014.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that such information is accumulated and communicated to the management of our General Partner, including our General Partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure.

Our management, including our President and Chief Executive Officer and our Senior Vice President and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) (“Disclosure Controls”) will prevent 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 detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. 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 control. 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 in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

The management of our General Partner evaluated, with the participation of the Certifying Officers, the effectiveness of our Disclosure Controls and procedures as of the end of the period covered by this report, pursuant to Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2014, the end of the period covered by this report our Disclosure Controls and procedures were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended March 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our General Partner’s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer 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 principal executive officer and principal financial officer pursuant to 18 U.S.C. 1350 are furnished with this Quarterly Report on Form 10-Q as Exhibits 32.1 and 32.2.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please read under the captions “— Regulation of Operations — Interstate Transportation Pipeline Regulation” and “— Environmental Matters” in our Annual Report for more information.

Item 1A. Risk Factors

Information about material risks related to our business, financial conditions and results of operations for the quarter ended March 31, 2014, does not materially differ from those set out in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013. These risks are not the only risks facing the Partnership.

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Item 6. Exhibits

Exhibit Number	Exhibit
2.1	Limited Liability Company Unit Purchase and Sale Agreement, dated as of January 22, 2014 by and between American Midstream, LLC and ArcLight Energy Partners Fund V, L.P. (filed as Exhibit 2.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on January 22, 2014).
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (filed as Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2*	Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated August 9, 2013 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 15, 2013).
3.3*	Amendment to the Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated October 28, 2013 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 1, 2013).
3.4*	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated January 31, 2014 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on February 4, 2014).
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*	Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC, dated April 15, 2013 (filed as Exhibit 3.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 19, 2013).
3.7*	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC, effective February 5, 2014 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on February 10, 2014).
4.1	Warrant to Purchase Common Units of American Midstream Partners, LP, dated February 5, 2014 (filed as Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on February 10, 2014).
10.1	Series B Unit Purchase Agreement by and among American Midstream Partners, LP and The Purchasers Named on Schedule A Thereto, dated January 22, 2014 (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on January 22, 2014).
10.2	First Amendment to Series B Unit Purchase Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated January 31, 2014 (filed as Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-35257) filed on February 4, 2014).
10.3	Construction and Field Gathering Agreement by and between HPIP Lavaca, LLC and Penn Virginia Oil & Gas, L.P., dated January 31, 2014 (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on February 4, 2014).
31.1*	Certification of Stephen W. Bergstrom, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2014 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Daniel C. Campbell, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2014 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Stephen W. Bergstrom, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2014 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Daniel C. Campbell, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the March 31, 2014

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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

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- ** Submitted electronically herewith

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: May 12, 2014

AMERICAN MIDSTREAM PARTNERS, LP

By: American Midstream GP, LLC, its general partner

By: /s/ Stephen W. Bergstrom
Name: Stephen W. Bergstrom
Title: President and Chief Executive Officer
(principal executive officer)

By: /s/ Daniel C. Campbell
Name: Daniel C. Campbell
Title: Senior Vice President & Chief Financial Officer
(principal financial officer)

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