American Midstream Partners, LP
Form 10-Q
November 14, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012
or

c 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.)
1614 15th Street, Suite 300 Denver, CO	80202
(Address of principal executive offices)	(Zip code)

(720) 457-6060
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes ¨ No

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

There were 4,623,436 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of November 12, 2012. 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:

ASC	Accounting Standards Codification; trademark of the Financial Accounting Standards Board (FASB).
GAAP	General Accepted Accounting Principles: Accounting principles generally accepted in the United States of America.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.
FERC	Federal Energy Regulatory Commission.
Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
MBbl	One thousand barrels.
MMBbl	One million barrels.
Btu	British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
MMBtu	One million British thermal units.
Mcf	One thousand cubic feet.
Gal	Gallons.
/d	Per day.
Mcf	One thousand cubic feet.
MMcf	One million cubic feet.
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.
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.
Fractionation	Process by which natural gas liquids are separated into individual components

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)

	September 30, 2012	December 31, 2011
	(in thousands)	
Assets		
Current assets		
Cash and cash equivalents	$497	$871
Accounts receivable	1,776	1,218
Unbilled revenue	17,603	19,745
Risk management assets	1,347	456
Other current assets	2,924	3,323
Total current assets	24,147	25,613
Property, plant and equipment, net	217,552	170,231
Risk management assets - long term	207	—
Other assets, net	4,520	3,707
Total assets	$246,426	$199,551
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$3,040	$837
Accrued gas purchases	12,912	14,715
Risk management liabilities	—	635
Accrued expenses and other current liabilities	5,207	7,086
Total current liabilities	21,159	23,273
Other liabilities	8,884	8,612
Long-term debt	118,650	66,270
Total liabilities	148,693	98,155
Commitments and contingencies (see Note 12)		
Partners' capital		
General partner interest (185 and 185 thousand units issued and outstanding as of September 30, 2012 and December 31, 2011, respectively)	1,669	1,091
Limited partner interest (9,108 and 9,087 thousand units issued and outstanding as of September 30, 2012 and December 31, 2011, respectively)	88,202	99,890
Accumulated other comprehensive income	455	415
Total partners' capital	90,326	101,396
Total liabilities and partners' capital	$239,019	$199,551
Noncontrolling interests	7,407	—
Total liabilities, partners' capital and noncontrolling interest	$246,426	$199,551

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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands, except for per unit amounts)			
Revenue	$58,086	$57,005	$148,363	$190,374
Realized gain (loss) on early termination of commodity derivatives	—	—	—	(2,998)
Unrealized gain (loss) on commodity derivatives	(1,762)	953	1,732	(19)
Total revenue	56,324	57,958	150,095	187,357
Operating expenses:				
Purchases of natural gas, NGLs and condensate	43,900	47,359	107,348	157,725
Direct operating expenses	5,264	3,385	12,031	9,548
Selling, general and administrative expenses	3,679	2,497	10,676	7,649
Advisory services agreement termination fee	—	2,500	—	2,500
Equity compensation expense	474	331	1,272	2,989
Depreciation and accretion expense	5,536	5,261	15,819	15,468
(Gain) loss on sale of assets, net	(4)	(586)	(126)	(586)
Total operating expenses	58,849	60,747	147,020	195,293
Operating income (loss)	(2,525)	(2,789)	3,075	(7,936)
Other income (expenses):				
Interest expense	(1,501)	(1,378)	(3,083)	(3,923)
Net income (loss)	$(4,026)	$(4,167)	$(8)	$(11,859)
Net income (loss) attributable to noncontrolling interests	$249	$—	$249	$—
Net income (loss) attributable to the Partnership	$(4,275)	$(4,167)	$(257)	$(11,859)
General partners' interest in net income (loss)	$(85)	$(83)	$(5)	$(237)
Limited partners' interest in net income (loss)	$(4,190)	$(4,084)	$(252)	$(11,622)
Limited partners' net income (loss) per unit (basic and diluted) (See Note 9)	$(0.46)	(0.53)	(0.03)	(1.85)
Weighted average number of units used in computation of limited partners' net income (loss) per unit (basic and diluted)	9,108	7,774	9,103	6,296

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Net income (loss)	$(4,275)	$(4,167)	$(257)	$(11,859)
Unrealized gain (loss) on post retirement benefit plan assets and liabilities	23	83	40	83
Comprehensive income (loss)	$(4,252)	$(4,084)	$(217)	$(11,776)
Less: Comprehensive income (loss) attributable to noncontrolling interests	$249	$—	$249	$—
Comprehensive income attributable to Partnership	$(4,501)	$(4,084)	$(466)	$(11,776)

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)

	Limited Partner Common Units	Limited Partner Subordinated Units	Limited Partner Interest	General Partner Units	General Partner Interest	Accumulated Other Comprehensive Income	Total Partners' Capital	Noncontrolling Interest
	(in thousands)							
Balances at December 31, 2010	5,363	—	$83,624	109	$2,124	$ 56	$85,804	—
Net income (loss)	—	—	(11,622)	—	(237)	—	(11,859)	—
Recapitalization	(4,602)	4,526	—	76	—	—	—	—
Issuance of common units to public, net of offering costs	3,750	—	69,085	—	—	—	69,085	—
Unitholder distributions	—	—	(40,247)	—	(814)	—	(41,061)	—
LTIP vesting	15	—	318	—	(318)	—	—	—
Unit based compensation	—	—	218	—	1,016	—	1,234	—
Adjustments to other post retirement plan assets and liabilities	—	—	—	—	—	83	83	—
Balances at September 30, 2011	4,526	4,526	$101,376	185	$1,771	$ 139	$103,286	—
Balances at December 31, 2011	4,561	4,526	$99,890	185	$1,091	$ 415	$101,396	—
Acquisition of noncontrolling interests	—	—	—	—	—	—	—	7,407
Net income (loss)	—	—	(252)	—	(5)	—	(257)	249
Unitholder contributions	—	—	—	—	13	—	13	—
Unitholder distributions	—	—	(11,809)	—	(241)	—	(12,050)	—
Net distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(249)
LTIP vesting	20	—	364	—	(364)	—	—	—
Tax netting repurchase	(4)	—	(88)	—	—	—	(88)	—
Unit based compensation	5	—	97	—	1,175	—	1,272	—
Adjustments to other post retirement plan assets and liabilities	—	—	—	—	—	40	40	—
Balances at September 30, 2012	4,582	4,526	$88,202	185	$1,669	$ 455	$90,326	$ 7,407

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)

	Nine Months Ended September 30, 2012	2011
	(in thousands)	
Cash flows from operating activities		
Net income (loss)	$(8)	$(11,859)
Adjustments to reconcile net income (loss) to net cash provided (used) in operating activities:		
Depreciation and accretion expense	15,819	15,468
Amortization of deferred financing costs	493	1,121
Unrealized (gain) loss on derivative contracts	(1,733)	19
Unit based compensation	1,272	1,234
OPEB plan net periodic (benefit) cost	(61)	—
(Gain) loss on sale of assets	(126)	(586)
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	(558)	(536)
Unbilled revenue	6,677	4,108
Risk management assets	—	(670)
Other current assets	1,285	(173)
Other assets, net	(65)	33
Accounts payable	1,396	(108)
Accrued gas purchases	(5,833)	(3,397)
Accrued expenses and other current liabilities	(1,879)	2,717
Other liabilities	(203)	(272)
Net cash provided (used) in operating activities	16,476	7,099
Cash flows from investing activities		
Cost of acquisition, net of cash acquired	(51,377)	—
Additions to property, plant and equipment	(4,465)	(4,890)
Proceeds from disposals of property, plant and equipment	126	125
Net cash provided (used) in investing activities	(55,716)	(4,765)
Cash flows from financing activities		
Unit holder contributions	13	—
Unit holder distributions	(12,050)	(41,061)
Net distributions to noncontrolling interest owners	(249)	—
Proceeds upon issuance of common units to public, net of offering costs	—	69,085
LTIP tax netting unit repurchase	(88)	—
Payments on other loan	—	(615)
Deferred debt issuance costs	(1,140)	(2,256)
Payments on long-term debt	(42,310)	(103,870)
Borrowings on long-term debt	94,690	76,850
Net cash provided (used) in financing activities	38,866	(1,867)
Net increase (decrease) in cash and cash equivalents	(374)	467
Cash and cash equivalents		
Beginning of period	871	63
End of period	$497	$530

Supplemental cash flow information		
Interest payments	$1,894	$3,201
Supplemental non-cash information		
Increase (decrease) in accrued property, plant and equipment	$808	$353

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 acquiring and operating certain natural gas pipeline and processing businesses. We provide natural gas gathering, treating, processing, marketing, and transportation services in the Gulf Coast and Southeast regions of the United States. We hold our assets in a series of wholly owned limited liability companies as well as a limited partnership. Our capital accounts consist of general partner interests and limited partner interests.

We are controlled by our general partner, American Midstream GP, LLC, which is a wholly owned subsidiary of AIM Midstream Holdings, LLC.

Our assets are primarily located in Alabama, Louisiana, Mississippi, Tennessee, and Texas. We organize our operations into two business segments: (1) Gathering and Processing; and (2)Transmission.

Our Gathering and Processing segment is an integrated midstream natural gas system that provides gathering, compression, treating, processing, fractionation, transportation, and sales of natural gas, NGLs and condensate. Our Gathering and Processing segment includes the following systems:

- The Gloria gathering system provides gathering and compression services through our assets, as well as processing services through processing arrangements. The Gloria system is a Section 311 intrastate pipeline located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana consisting of approximately 110 miles of pipeline with diameters ranging from 3 to 16 inches and 3 compressors with a combined size of 1,877 horsepower.
- The Lafitte gathering system is a Section 311 intrastate pipeline consisting of approximately 40 miles of gathering pipeline, with diameters ranging from 4 to 12 inches. The Lafitte system originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana at the Alliance Refinery owned by ConocoPhillips Corporation and is connected to our Gloria gathering system.
- The Bazor Ridge gathering and processing system consists of approximately 160 miles of pipeline with diameters ranging from 3 to 8 inches and 3 compressor stations with a combined compression capacity of 1,069 horsepower. Our Bazor Ridge system is located in Jasper, Clarke, Wayne and Greene Counties of Mississippi.
- The Quivira gathering system consists of approximately 34 miles of pipeline, with a 12- inch diameter mainline and several laterals ranging in diameter from 6 to 8 inches. The system originates offshore of Iberia and St. Mary Parishes of Louisiana in Eugene Island Block 24 and terminates onshore at a connection with the Burns Point Plant.
- The Burns Point Plant is located in St. Mary Parish, Louisiana, where raw natural gas is processed through a cryogenic processing plant that is jointly owned by us and the operator, Enterprise.
- The Chatom gathering, processing and fractionation plant is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 MMcf/d refrigeration processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 29-mile gas gathering system, to which we have an 87.4% undivided interest.
- The Offshore Texas system consists of the GIGS and Brazos systems, two parallel gathering systems that share common geography and operating characteristics. The Offshore Texas system provides gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico region. The Offshore Texas system consists of approximately 56 miles of pipeline with diameters ranging from 6 to 16 inches.
- The Alabama Processing system consists of 2 small skid-mounted treating and processing plants that we refer to, individually, as Atmore and Wildfork. These treating and processing plants are located in Escambia and Monroe Counties of Alabama.
- The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coal bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transco Pipeline system, an interstate pipeline owned by The Williams Companies, Inc. The Magnolia system consists of approximately 116 miles of pipeline with small-diameter gathering lines and trunk lines ranging from 6 to 24 inches in diameter and 1 compressor station with 3,328 horsepower.

• Our other gathering and processing systems include the Fayette and Heidelberg gathering systems, located in

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Fayette County, Alabama and Jasper County, Mississippi, respectively.

Our Transmission segment includes intrastate and interstate pipelines that transport natural gas through Alabama, Louisiana, Mississippi and Tennessee as follows:

- Our Bamagas system is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama to 2 power plants owned by Calpine Corporation, in Morgan County, Alabama. The Bamagas system consists of 52 miles of high pressure, 30 inch pipeline.
- The MLGT system is an intrastate transmission system that sources natural gas from interconnects with the FGT Pipeline system, the Tetco Pipeline system, the Transco Pipeline system and our Midla system to a Baton Rouge, Louisiana refinery owned and operated by ExxonMobil and 7 other industrial customers. Our MLGT system is comprised of approximately 54 miles of pipeline with diameters ranging from 3 to 14 inches.
- Our other intrastate transmission systems include the Chalmette system, located in St. Bernard Parish, Louisiana, and the Trigas system, located in 3 counties in northwestern Alabama.
- We also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.
- Our Midla system is a FERC regulated system that includes approximately 370 miles of interstate pipeline that runs from the Monroe gas field in northern Louisiana south through Mississippi to Baton Rouge, Louisiana.
- Our AlaTenn system is a FERC regulated system that includes approximately 295 miles of interstate pipeline that runs through the Tennessee River Valley from Selmer, Tennessee to Huntsville, Alabama and serves an 8 county area in Alabama, Mississippi and Tennessee.

Initial Public Offering

On July 26, 2011, we commenced the initial public offering of our common units pursuant to our Registration Statement on Form S-1, Commission File No. 333-173191 (the “Registration Statement”), which was declared effective by the SEC on July 26, 2011. Citigroup Global Markets Inc. and Merrill Lynch, Pierce, Fenner, & Smith Incorporated acted as representatives of the underwriters and as joint book-running managers of the offering.

Upon closing of our IPO on August 1, 2011, we issued 3,750,000 common units pursuant to the Registration Statement at a price per unit of $21.00. The Registration Statement registered the offer and sale of securities with a maximum aggregate offering price of $90,562,500. The aggregate offering amount of the securities sold pursuant to the Registration Statement was $78,750,000.

After deducting underwriting discounts and commissions of $4.9 million paid to the underwriters, offering expenses of $4.2 million and a structuring fee of $0.6 million, the net proceeds from our IPO were $69.1 million. We used all of the net offering proceeds from our IPO for the uses described in the final prospectus filed with the SEC pursuant to Rule 424(b) on July 27, 2011.

On July 29, 2011, in connection with the closing of our initial public offering, our general partner contributed 76,019 of our common units to us in exchange for 76,019 general partner units in order to maintain its 2.0% general partnership interest in us. This transaction was exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended.

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 audited financial statements but does not include disclosures required by GAAP for annual periods. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair statement of financial position as of September 30, 2012, and December 31, 2011, condensed consolidated statement of operations for the three and nine months ended September 30, 2012 and 2011, statement of changes in partners’ capital and noncontrolling interest for the nine months ended September 30, 2012 and 2011, and statements of cash flows for the nine months ended September 30, 2012 and 2011.

Our financial results for the three and nine months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2012. These unaudited condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2011 (“Annual Report”) filed on March 19, 2012.

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Consolidation Policy

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. We hold an undivided interest in a gas processing facility in which we are responsible for our proportionate share of the costs and expenses of the facility. Our consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of this undivided interest.

Use of Estimates

When preparing 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 (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Accounting for Regulated Operations

Certain of our natural gas pipelines are subject to regulations by the FERC. The FERC exercises statutory authority over matters such as construction, transportation rates we charge and our underlying accounting practices and ratemaking agreements with customers. Accordingly, we record costs that are allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a non-regulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would be recorded under GAAP for our regulated entities. As of September 30, 2012 and December 31, 2011, we had no such material regulatory assets or liabilities.

2. Summary of Significant Accounting Policies

Revenue Recognition and the Estimation of Revenues

We recognize revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonably assured. We record revenue and cost of product sold on a gross basis for those transactions where we act as the principal and take title to natural gas, NGLs or condensates that are purchased for resale. When our customers pay us a fee for providing a service such as gathering, treating or transportation, we record those fees separately in revenues. For the three and nine months ended September 30, 2012 and 2011, respectively, we recognized the following revenues by category:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Transportation - firm	$2,230	$2,077	$7,703	$7,572
Transportation - interruptible	798	888	2,838	2,671
Sales of natural gas, NGLs and condensate	53,771	53,833	134,153	179,545
Other	1,287	207	3,669	586
Revenue	$58,086	$57,005	$148,363	$190,374

Limited Partners' Net Income (Loss) Per Common Unit

We compute limited partners' net income (loss) per common unit by dividing our limited partners' interest in net income (loss) by the weighted average number of common units outstanding during the period. The overall computation, presentation and disclosure requirements for our limited partners' net income (loss) per common unit are made in accordance with the “Earnings per Share” Topic of the Codification as described in the Annual Report. All per unit computations give effect to the retroactive application of the reverse unit split as described in Note 9, “Partners’ Capital”.

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Noncontrolling Interest

Noncontrolling interest represents the noncontrolling interest holders' proportionate share of the equity of the Chatom Assets. Noncontrolling interest is adjusted for the noncontrolling interest holders' proportionate share of the earnings or losses. Management reports noncontrolling interest in the Chatom Assets in the financial statements pursuant to paragraph ASU No. 810-10-65-1. The 12.6% noncontrolling interest is held by other non-affiliated working interest owners.

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11 Disclosures about Offsetting Assets and Liabilities. The ASU requires additional disclosures about the impact of offsetting, or netting, on a company’s financial position, and is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods, and retrospectively for all comparative periods presented. Under GAAP, derivative assets and liabilities can be offset under certain conditions. The ASU requires disclosures showing both gross information and net information about instruments eligible for offset in the balance sheet. Except for additional disclosures related to our offsetting arrangements, the adoption of the amended guidance is not expected to have a material effect on the Partnership's consolidated financial statements.

3. Acquisitions

Burns Point Plant Interest

On December 1, 2011, we acquired a 50% undivided interest (“Interest”) in the Burns Point Plant (“Plant”) from Marathon Oil Company (“Seller”) for total cash consideration of $35.5 million. No liabilities of the Seller were assumed. The purchase was effective November 1, 2011 (“Effective Date”) with our assumption of insurable risks, operating liabilities and entitlement to in-kind revenues as of that date. The remaining 50% undivided interest is owned by the Plant operator, Enterprise Gas Processing, LLC (“Operator”). The Plant, which is an unincorporated joint venture, is governed by a construction and operating agreement (“Agreement”).

The Plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The Plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. The Quivira system currently supplies approximately 88% of the inlet volume to the Plant. The residue gas is transported, via pipeline to Gulf South and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC (“Promix”), an Enterprise-operated fractionator. The current capacity of the plant is 165.0 MMcf/d. The acquisition complemented our existing assets given it is the majority of the inlet volume to the Quivira system and is included in our Gathering and Processing segment.

The Plant is not a legal entity but rather an asset that is jointly owned by the Operator and us. We acquired an interest in the asset group and do not hold an interest in a legal entity. Each of the owners in the asset group is proportionately liable for the liabilities. Outside of the rights and responsibilities of the Operator, we and the Operator have equal rights and obligations to the assets. Significant non-capital and maintenance capital expenditures, plant expansions and significant plant dispositions require the approval of both owners.

Under the terms of the Agreement, the Operator is required to provide monthly production allocation and expense statements to us and is not required to prepare and provide to us balance sheet information or stand-alone financial statements. Historically, balance sheet and stand-alone financial statements for the Plant have not been prepared and are, therefore, not available.

We reviewed the governance structure of the Plant and applied the concepts discussed in ASC-810-10-45 (“Other Presentation Matters.”) We determined that while the facility is an unincorporated joint venture, the asset group is jointly controlled with the Operator.

We reviewed the requirements for the application of the equity method of accounting, given the joint control attribute of the Plant, and because the necessary complete Plant financial statements are not, nor expected to be, available from the Operator, we have elected to account for our Interest using the proportionate consolidation method. Our Interest in the Plant is recorded in property, plant and equipment, net on the consolidated balance sheet and will be depreciated over 40 years. Under this method, we include in our consolidated statement of operations the value of our Plant revenues taken in-kind and the Plant expenses reimbursed to the Operator.

Chatom Gathering, Processing and Fractionation Plant

Effective July 1, 2012, we acquired an 87.4% undivided interest in the Chatom processing and fractionation plant and associated gathering infrastructure (“Chatom Assets”) from affiliates of Quantum Resources Management, LLC. The acquisition fair value of consideration of $51.4 million includes a credit associated with the cash flow the Chatom Assets

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generated between January 1, 2012, and the effective date of July 1, 2012. The consideration paid by the Partnership consisted of cash, which was funded under borrowings under our revolving credit facility.

The Chatom Assets are located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 MMcf/d refrigeration processing plant, a 1,900 Bbl/d fractionation unit, a160 long-ton per day sulfur recovery unit, and a 29 mile gas gathering system. We believe the Chatom Assets will be accretive to the Partnership's distributable cash flow per unit.

Our 87.4% undivided interest in the Chatom Assets contributed $13.1 million of revenue and $1.7 million of net income attributable to the partnership, which are included in the condensed consolidated statement of operations for the three and nine months ended September 30, 2012, respectively.

The following table presents unaudited pro forma consolidated information of the Partnership, adjusted for the acquisition of the Chatom Assets, as if the acquisition had occurred on January 1, 2011:

	Nine months ended September 30, 2012
	(unaudited, in thousands)
Revenue	$185,851
Net income	$1,926

These amounts have been calculated after applying the Partnership's accounting policies and adjusting the results to reflect i) additional depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, and ii) recording pro forma interest expense on debt that would have been incurred to acquire the Chatom Assets as of January 1, 2012.

The following table presents unaudited pro forma consolidated information of the Partnership, adjusted for the acquisition of the Chatom Assets, as if the acquisition had occurred on January 1, 2011:

	Three months ended September 30, 2011	Nine months ended September 30, 2011
	(unaudited, in thousands)	
Revenue	$68,721	$221,579
Net loss	$(4,580)	$(11,543)

These amounts have been calculated after applying the Partnership's accounting policies and adjusting the results to reflect i) additional depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, and ii) recording pro forma interest expense on debt that would have been incurred to acquire the Chatom Assets as of January 1, 2011.

The following table presents the fair value of consideration transferred to acquire the Chatom Assets and the amounts of identified assets acquired and liabilities assumed at the acquisition date, as well as the fair value of the 12.6% noncontrolling interest in the Chatom Assets at the acquisition date:

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	(in thousands)
Cash	$51,377
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Unbilled revenue	$4,535
Property, plant and equipment	58,279
Asset retirement cost	452
Accounts payable	(399)
Accrued gas purchases	(3,631)
Asset retirement obligations	(452)
Noncontrolling interest	(7,407)
Total identifiable net assets	$51,377

The fair value of the property, plant and equipment and noncontrolling interests were estimated by applying a combination of the market and income approaches. This fair value measurements are based on significant inputs not observable in the market and thus represents a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimates are based on i) an assumed cost of capital of 9.25%, ii) an assumed terminal value based on the present value of estimated EBITDA, iii) an inflationary cost increase of 2.5%, iv) forward market prices as of July 2012 for natural gas and crude oil, iv) a Federal tax rate of 35% and a state tax rate of 6.5%, and v) an increase in processed and fractionated volumes in 2013, declining thereafter. Working capital was estimated using net realizable value. Accrued revenue is deemed to be fully collectible at July 1, 2012.

4. 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 and NGL 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 nine months ended September 30, 2012 and period ended December 31, 2011, no allowances on or write-offs of accounts receivable were recorded.

ConocoPhillips Corporation, Shell Trading (US) Company, Enbridge Marketing (US) L.P., and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $13.3 million, $9.9 million, $6.9 million, and $6.5 million, respectively, of our consolidated revenue in the consolidated statement of operations in the three months ended September 30, 2012. ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $24.3 million, $10.5 million, and $10.1 million, respectively, of our consolidated revenue in the consolidated statement of operations in the three months ended September 30, 2011.

ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $42.7 million, $23.9 million, and $18.3 million, respectively, for nine months ended September 30, 2012 and $78.6 million, $33.4 million, and $29.8 million, respectively, for the nine months ended September 30, 2011.

5. 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. 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

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directors of our general partner. During the nine months ended September 30, 2012 and 2011, we entered into various commodity swap, option, and collar arrangements.

In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from canceling our then-existing NGL swap contracts and entering into new NGL swap contracts with an existing counterparty that extend through the end of 2012.

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 September 30, 2012, we have not posted collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

As of September 30, 2012, the aggregate notional volume of our commodity derivatives was 11.4 million gallons.

As of September 30, 2012 and December 31, 2011, the fair value associated with our derivative instruments were recorded in our financial statements, under the caption Risk management assets and Risk management liabilities, as follows:

	September 30, 2012	December 31, 2011
	(in thousands)	
Risk management assets:		
Commodity derivatives	$1,347	$456
Risk management assets - long term:		
Commodity derivatives	$207	$—
Risk management liabilities:		
Commodity derivatives	$—	$635
Risk management liabilities - long term:		
Commodity derivatives	$—	$—

We recorded the following unrealized mark-to-market gains (losses) in the condensed consolidated statement of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Commodity derivatives	$(1,762)	$953	$1,732	$(19)

6. 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 – 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 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 and volatility curves, as well as other relevant economic measures. To extrapolate a forecast of future cash flows, discount

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factors are utilized. The inputs are obtained from independent pricing services, and we have made no adjustments to the obtained prices.
We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivatives contracts held. We will recognize transfers between levels at the end of the reporting period for which the transfer has occurred, there were no such transfers for nine months ended September 30, 2012 or period ended December 31, 2011.
Quantitative Information about Level 3 Fair Value Measurements

	Fair Value at September 30, 2012 (in thousands)	Valuation Technique	Unobservable Input	Range		
Commodity derivative asset (liability), net	$1,553	Forecasted future cash flow	Forward commodity prices	$0.965	to	$1.220
			Volatility curves	20.0%	to	34.8%
			Discount factors	0.973	to	1.070

The significant unobservable inputs used in the fair value measurement of the commodity derivative asset (liability) are forward commodity prices and volatility curves. Significant increases or decreases in the inputs in isolation would result in a significantly lower or higher fair value measurement.
Fair Value of Financial Instruments
The following table sets forth by level within the fair value hierarchy, our net derivative assets (liabilities) that were measured at fair value on a recurring basis as of September 30, 2012 and December 31, 2011:

	Carrying Amount	Estimated Fair Value Level 1 (in thousands)	Level 2	Level 3	Total
Commodity derivative asset (liability), net					
September 30, 2012	$1,553	$—	$—	$1,553	$1,553
December 31, 2011	$(179)	$—	$—	$(179)	$(179)

Changes in Level 3 Fair Value Measurements
The table below includes a roll forward of the balance sheet amounts (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources). Contracts classified as Level 3 are valued using price inputs available from public markets to the extent that the markets are liquid or the relevant settlement periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Fair value asset (liability), beginning of period	$3,315	$(302)	$(179)	$—
Realized gain (loss) on early termination of commodity derivatives	—	—	—	(2,998)
Unrealized gain (loss) on commodity derivatives	(1,762)	953	1,732	(19)
Purchases	—	—	—	670
Settlements	—	—	—	2,998
Fair value asset (liability), end of period	$1,553	$651	$1,553	$651

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Also included in revenue were $1.0 million and $(0.4) million in realized gains (losses) for the three months ended September 30, 2012 and 2011, respectively, and $1.6 million and $(1.3) million in realized gains (losses) for the nine months ended September 30, 2012 and 2011, respectively, representing our monthly swap settlements.

7. Property, Plant and Equipment

Property, plant and equipment, net, as of September 30, 2012 and December 31, 2011 were as follows:

	Useful Life	September 30, 2012	December 31, 2011
	(in years)	(in thousands)	
Land		$2,254	$41
Construction in progress		3,347	3,380
Buildings and improvements	4 to 40	1,439	1,490
Processing and treating plants	8 to 40	97,816	49,396
Pipelines	5 to 40	157,042	146,788
Compressors	4 to 20	8,681	7,437
Equipment	8 to 20	2,078	1,198
Computer software	5	1,691	1,500
Total property, plant and equipment		274,348	211,230
Accumulated depreciation		(56,796)	(40,999)
Property, plant and equipment, net		$217,552	$170,231

Of the gross property, plant and equipment balances at September 30, 2012 and December 31, 2011, $24.8 million and $24.0 million were related to AlaTenn and Midla, our FERC regulated interstate assets.

Asset Retirement Obligations

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

During the nine months ended September 30, 2012 and year ended December 31, 2011, we recognized $0.5 million and $0.9 million of AROs included in other liabilities for specific assets that we intend to retire for operational purposes.

We recorded accretion expense, which is included in depreciation expense, of less than $0.1 million and $0.3 million in our consolidated statements of operations for the three months ended September 30, 2012 and 2011, respectively, and less than $0.1 million and $1.0 million in our consolidated statements of operations for the nine months ended September 30, 2012 and 2011, respectively, related to these AROs.

8. Long-Term Debt

On June 27, 2012, we amended our credit facility to increase the Commitments from an aggregate principal amount of $100 million to an aggregate principal amount of $200 million, evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto. The credit facility also provides for a $50 million dollar accordion feature. If the accordion feature were to be fully exercised, the total commitment under the existing facility would be $250 million.

The credit facility provides for a maximum borrowing equal to the lesser of (i) $200 million or (ii) 4.50 times adjusted consolidated EBITDA. We may elect to have loans under the credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.25% to 3.50% 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 1/2 of 1% (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”, and (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.25% to 2.50% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan. For the nine months ended September 30, 2012 and 2011, the weighted average interest rate on borrowings under our credit facility was approximately 4.09% and 7.37%, respectively.

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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 our subsidiaries ("Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the 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 leverage ratio test (not to exceed 4.50 times) and a minimum interest coverage ratio test (not less than 2.50 times). We were in compliance with all of the covenants under our credit facility as of September 30, 2012.

As of September 30, 2012, the total leverage ratio test, one of the primary financial covenants that we are required to maintain under our credit facility, was 4.31. Our ability to comply with these covenants and ratios in the future will be affected by the levels of debt and of cash flow from our operations, among other factors.

In order to remain in compliance with our financial covenants and ratios under our credit facility, we believe that we have several options available to us that we may pursue separately or in combination. First, subject to market conditions, we have the ability to issue debt or equity securities to refinance or pay down outstanding borrowings under our credit facility and to fund future growth capital expenditures. Second, we may request a waiver from the lenders in our credit facility. Third, we may seek to reduce our debt by amounts that exceed our operating cash flows through actions such as a reduction in capital expenditures; suspension of our quarterly distributions to subordinated unitholders and, thereafter, unitholders; the sale of assets; further reduction of operating and administrative costs; or other steps to enhance liquidity and reduce debt and avoid default.

If we were not in compliance with the financial covenants in the credit facility, or if we did not enter into an agreement to refinance or extend the due date on the credit facility, our debt could become due and payable upon acceleration by the lenders in our banking group. In addition, failure to comply with any of the covenants under our credit facility could adversely affect our ability to fund ongoing operations and growth capital requirements as well as our ability to pay distributions to our unitholders.

Our outstanding borrowings under the credit facility at September 30, 2012 and December 31, 2011, respectively, were:

	September 30, 2012	December 31, 2011
	(in thousands)	
Revolving loan facility	$118,650	$66,270

At September 30, 2012 and December 31, 2011, letters of credit outstanding under the credit facility were $0.6 million.

In connection with our credit facility and amendments thereto, we incurred $3.6 million in debt issuance costs that are being amortized on a straight-line basis over the term of the credit facility.

9. Partners' Capital

Our capital accounts are comprised of approximately 2% general partner interest and 98% limited partner interests. Our limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. Our general partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the incentive distribution rights that are nonvoting limited partner interests held by our general partner.

On August 1, 2011, we closed our IPO of 3,750,000 common units at an offering price of $21.00 per unit. After deducting underwriting discounts and commissions of $4.9 million paid to the underwriters, estimated offering expenses of $4.2 million and a structuring fee of $0.6 million, the net proceeds from our initial public offering were $69.1 million. We used all of the net offering proceeds from our initial public offering for the uses described in the Annual Report.

Immediately prior to the closing of our IPO the following recapitalization transactions occurred:

- each common unit held by AIM Midstream Holdings reverse split into 0.485 common units, resulting in the ownership by AIM Midstream Holdings of an aggregate of 5,327,205 common units, representing an

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aggregate 97.1% limited partner interest in us;

- the common units held by AIM Midstream Holdings then converted into 801,139 common units and 4,526,066 subordinated units:
- each general partner unit held by our general partner reverse split into 0.485 general partner units, resulting in the ownership by our general partner of an aggregate of 108,718 general partner units, representing a 2.0% general partner interest in us;
- each common unit held by participants in our LTIP, reverse split into 0.485 common units, resulting in their ownership of an aggregate of 50,946 common units, representing an aggregate 0.9% limited partner interest in us, and
- each outstanding phantom unit granted to participants in our LTIP reverse split into 0.485 phantom units, resulting in their holding an aggregate of 209,824 phantom units.

In connection with the closing of our IPO and immediately following the recapitalization transactions, the following transactions also occurred:

- AIM Midstream Holdings contributed 76,019 common units to our general partner as a capital contribution, and
- our general partner contributed the common units contributed to it by AIM Midstream Holdings to us in exchange for 76,019 general partner units in order to maintain its 2.0% general partner interest in us.

The numbers of units outstanding were as follows:

	September 30, 2012	December 31, 2011
	(in thousands)	
Limited partner common units	4,582	4,561
Limited partner subordinated units	4,526	4,526
General partner units	185	185

The outstanding units noted above reflect the retroactive treatment of the reverse unit split resulting from the recapitalization described above.

Net Income (Loss) attributable to Limited Common and General Partner Units

Net income (loss) attributable to the general partner and the limited partners (common unit holders) is allocated in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income (loss) per limited partner common unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding limited partner common units during the period.

Unvested share-based payment awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net income per limited partner unit.

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 our 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 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 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 determined basic and diluted net income (loss) per general partner unit and limited partner unit as follows:

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	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In thousands except unit amounts)			
Net income (loss) attributable to general partner and limited partners	$(4,275)	$(4,167)	$(257)	$(11,859)
Weighted average general partner and limited partner units outstanding (basic and diluted) (a)	9,293	7,932	9,288	6,421
General partner and limited partner net income (loss) per unit (basic and diluted)	(0.46)	(0.53)	(0.03)	(1.85)
Net income (loss) attributable to limited partners	$(4,190)	$(4,084)	$(252)	$(11,622)
Weighted average limited partner units outstanding (basic and diluted) (a)	9,108	7,774	9,103	6,296
Limited partners' net income (loss) per unit (basic and diluted)	(0.46)	(0.53)	(0.03)	(1.85)
Net income (loss) attributable to general partner	$(85)	$(83)	$(5)	$(237)
Weighted average general partner units outstanding (basic and diluted)	185	158	185	125
General partner net income (loss) per unit (basic and diluted)	$(0.46)	$(0.53)	$(0.03)	$(1.90)

a) Gives effect to the reverse unit split.

Distributions

We made distributions of $12.1 million and $7.4 million for the nine months ended September 30, 2012 and 2011, respectively. We made no distributions in respect of our general partner's incentive distribution rights.

In addition to the distributions described above, in August 2011, we made a special distribution of $33.7 million to participants in our long-term incentive plan ("LTIP") holding common units, AIM Midstream Holdings and our general partner.

10. Long-Term Incentive Plan

Our general partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our general partner adopted a long-term incentive plan ("LTIP") for its employees and consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our general partner adopted an amended and restated long-term incentive plan. On July 11, 2012, the board of directors of our general partner adopted a second amended and restated long-term incentive plan that effectively increased available awards by 871,750 units. At September 30, 2012 and December 31, 2011, 908,588 and 54,827 units, respectively, were available for future grant under the LTIP, giving retroactive treatment to the reverse unit split in connection with our recapitalization described in our Annual Report.

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. The board of directors of our general partner, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash. Although, our general partner has the option to settle in cash upon the vesting of phantom units, our general partner does not 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 ("DERs"). 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.

Prior to our initial public offering, the fair value of the grants issued was calculated by the general partner based on several valuation models, including: a discounted cash flow ("DCF") model, a comparable company multiple analysis and a comparable recent transaction multiple analysis. As it relates to the DCF model, the model includes certain market assumptions related to future throughput volumes, projected fees and/or prices, expected costs of sales and direct operating costs and risk adjusted discount rates. Both the comparable company analysis and recent transaction analysis contain significant assumptions consistent with the DCF model, in addition to assumptions related to comparability, appropriateness of multiples (primarily based on adjusted EBITDA and DCF) and certain assumptions in the calculation of enterprise value.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Outstanding at beginning of period	172,551	209,824	162,860	205,864
Granted	—	—	34,560	19,414
Forfeited	(12,517)	—	(12,517)	—
Vested	—	—	(24,869)	(15,454)
Outstanding at end of period	160,034	209,824	160,034	209,824
Fair value per unit	14.70 to $21.40	14.70 to $19.69	14.70 to $21.40	14.70 to $19.69

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 September 30, 2012 and 2011 was $0.5 million and $0.3 million, respectively, and for the nine months ended September 30, 2012 and 2011 was $1.3 million and $3.0 million, respectively, which is classified as equity compensation expense in the consolidated statement of operations and the non-cash portion in partners' capital on the consolidated balance sheet.

The total fair value of vested units at the time of vesting was $0.5 million and $1.2 million for the nine months ended September 30, 2012 and period ended December 31, 2011, respectively.

The total compensation cost related to unvested awards not yet recognized at September 30, 2012 and period ended December 31, 2011 was $2.1 million and $2.7 million, respectively, and the weighted average period over which this cost is expected to be recognized as of September 30, 2012 is approximately 1.3 years.

11. Post-Employment Benefits

We sponsor a contributory postretirement plan that provides medical, dental and life insurance benefits for qualifying U.S. retired employees (referred to as the "OPEB Plan").

Components of Net Periodic (Benefit) Cost recognized in the Condensed Consolidated Statements of Operations

	OPEB Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Net Periodic (Benefit) Cost				
Service cost	$1	—	$3	—
Interest cost	4	—	12	—
Expected return on plan assets	(16)	—	(49)	—
Amortization of net (gain) loss	(9)	—	(27)	—
Net periodic (benefit) cost	$(20)	$—	$(61)	$—

Future contributions to the Plans

We expect to make contributions to the OPEB Plan for the year ending December 31, 2012 of $0.1 million.

12. Commitments and Contingencies

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

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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-cancellable commitments related to certain contractual obligations as of September 30, 2012 are presented below:

	Payments Due by Period (in thousands)						
	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases and service contract	$2,282	$99	$416	$423	$400	$156	$788
Asset retirement obligation	8,559	—	—	—	—	8,107	452
Total	$10,841	$99	$416	$423	$400	$8,263	$1,240

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Operating leases	$254	$177	$692	$578
Asset retirement obligation	10	2	23	10
	$264	$179	$715	$588

Bazor Ridge Emissions Matter

In July 2011, in the course of preparing our annual filing for 2010 with the Mississippi Department of Environmental Quality ("MDEQ") as required by our Title V Air Permit, we determined that we underreported to the MDEQ the SO_2 (sulfur dioxide) emissions from the Bazor Ridge plant for 2009 and 2010. In addition, we determined that certain SO_2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act, or EPCRA, requiring notification of various governmental authorities. We did not make any such EPCRA notifications.

In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed, which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO_2 emissions. The MDEQ is currently processing this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. We have responded to this Information Request.

Although these current negotiations with the MDEQ and EPA are proceeding towards completion, either agency could initiate further enforcement proceedings with respect to these matters, which could result in additional monetary sanctions and our Bazor Ridge plant could become subject to significant restrictions or limitations on its operations. If the Bazor Ridge plant were subject to any curtailment or other operational restrictions as a result of any such enforcement proceeding, or were required to incur additional capital expenditures for additional emission controls through any permitting process, the costs to us could be material. In addition, if emission levels for our Bazor Ridge plant were not properly reported by the prior owner for periods before our acquisition, it is possible, though not probable at this time, that one or both of the MDEQ and the EPA may institute enforcement actions against us and/or the prior owner, in which case we may have an obligation under our purchase agreement with the prior owner to indemnify them for any resulting losses (as defined in the purchase agreement). We cannot estimate the likelihood or financial impact from any further enforcement proceedings at this time, and therefore, we have not recorded a loss contingency as the criteria under ASC 450, Contingencies, have not been met.

Separation Agreement

As of September 30, 2012, it is possible that we will incur cost of up to approximately $0.5 million in relation to a separation agreement with a former employee. In the event payment is made to the former employee pursuant to the separation agreement, we expect to receive payment from our insurance carrier of up to approximately 30% of the amount paid to the former employee.

13. Related-Party Transactions

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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 September 30, 2012 and 2011, administrative and operational services expenses of $2.9 million and $2.0 million, respectively, were charged to us by our general partner. During the nine months ended September 30, 2012 and 2011 administrative and operational services expense of $9.1 million and $7.4 million respectively, were charged to us by our general partner and increased primarily due to payroll costs. For the three months ended September 30, 2012, our general partner incurred approximately $0.2 million of costs associated with certain business development activities. If the business development activities result in a project that will be pursued and funded by the Partnership, we will reimburse our general partner for the business development costs related to that project.

Prior to our IPO, we had entered into an advisory services agreement with American Infrastructure MLP Management, L.L.C., American Infrastructure MLP PE Management, L.L.C., and American Infrastructure MLP Associates Management, L.L.C., as the advisors. The agreement provided for the payment of $0.3 million in 2010 and annual fees of $0.3 million plus annual increases in proportion to the increase in budgeted gross revenues thereafter. In exchange, the advisors agreed to provide us services in obtaining equity, debt, lease and acquisition financing, as well as providing other financial, advisory and consulting services. On August 1, 2011, and in connection with our IPO, we terminated the advisory services agreement in exchange for a one-time payment of $2.5 million. For the three and nine months ended September 30, 2011, less than $0.1 million was recorded to selling, general and administrative expenses under this agreement.

14. Reporting Segments

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

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.

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:

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	Three Months Ended September 30, 2012 Gathering and Processing (in thousands)	Transmission	Total	2011 Gathering and Processing	Transmission	Total
Revenue	$45,376	$ 12,710	$58,086	$41,218	$ 15,787	$57,005
Segment gross margin (a)	10,736	3,450	14,186	6,821	2,825	9,646
Unrealized gain (loss) on commodity derivatives (b)	(1,762)	—	(1,762)	953	—	953
Direct operating expenses	3,935	1,329	5,264	1,845	1,540	3,385
Selling, general and administrative expenses			3,679			2,497
Advisory services agreement termination fee			—			2,500
Equity compensation expense			474			331
Depreciation and accretion expense			5,536			5,261
(Gain) loss on sale of assets, net			(4)			(586)
Interest expense			1,501			1,378
Net income (loss)			(4,026)			(4,167)
Less: Net income (loss) attributable to noncontrolling interests			249			—
Net income (loss) attributable to the Partnership			$(4,275)			$(4,167)

	Nine Months Ended September 30, 2012 Gathering and Processing (in thousands)	Transmission	Total	2011 Gathering and Processing	Transmission	Total
Revenue	$111,246	$ 37,117	$148,363	$138,487	$ 51,887	$190,374
Segment gross margin (a)	29,198	11,817	41,015	22,988	9,661	32,649
Realized gain (loss) on early termination of commodity derivatives (b)	—	—	—	(2,998)	—	(2,998)
Unrealized gain (loss) on commodity derivatives (b)	1,732	—	1,732	(19)	—	(19)
Direct operating expenses	8,495	3,536	12,031	5,478	4,070	9,548
Selling, general and administrative expenses			10,676			7,649
Advisory services agreement termination fee			—			2,500
Equity compensation expense			1,272			2,989
Depreciation and accretion expense			15,819			15,468
(Gain) loss on sale of assets, net			(126)			(586)
Interest expense			3,083			3,923
Net income (loss)			(8)			(11,859)

Less: Net income (loss) attributable to noncontrolling interests	249	—
Net income (loss) attributable to the Partnership	$(257)	$(11,859)

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue less purchases of natural gas, NGLs and condensate. Segment gross margin for our Transmission segment consists of total revenue less purchases of natural gas. Gross margin consists of the sum of the segment gross margin for each segment. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful

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than, net income or cash flow from operations as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Effective January 1, 2011, we changed our segment gross margin measure to exclude unrealized non cash mark-to-market adjustments related to our commodity derivatives. For the three and nine months ended September 30, 2011, \$1.0 million and \$(0.1) million, respectively, in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized gain (loss) on early termination of commodity derivatives. For the three and nine months ended September 30, 2011, zero dollars and \$(3.0) million, respectively, in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin.

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.

15. Subsequent Events

Distribution

On October 23, 2012, we announced a distribution of \$0.4325 per unit payable on November 14, 2012 to unitholders of record on November 7, 2012.

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16. Subsidiary Guarantors

The Partnership has filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities. The subsidiaries of the Partnership (the "Subsidiaries") will be co-registrants with the Partnership, and the registration statement will register 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 September 30, 2012, the Subsidiaries have an investment in the non-guarantor subsidiaries equal to a 87.4% undivided interest in its Chatom Assets. 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 unaudited condensed consolidating financial information, the Partnership's investments in its Subsidiaries and the guarantor subsidiaries' investment in its 87.4% undivided interest in the Chatom Assets 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 September 30, 2012 and for the three and nine months ended is as follows:

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Condensed Consolidating Balance Sheet
As of September 30, 2012

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(in thousands)				
Assets					
Current assets					
Cash and cash equivalents	$1	$496	$ —	$—	$497
Accounts receivable	—	1,776	—	—	1,776
Unbilled revenue	—	11,999	5,604	—	17,603
Risk management assets	—	1,347	—	—	1,347
Other current assets	—	2,602	322	—	2,924
Total current assets	1	18,220	5,926	—	24,147
Property, plant and equipment, net	—	158,951	58,601	—	217,552
Risk management assets - long term	—	207	—	—	207
Investment in subsidiaries	90,325	51,863	—	(142,188)	—
Other assets, net	—	4,520	—	—	4,520
Total assets	$90,326	$233,761	$ 64,527	$(142,188)	$246,426
Liabilities and Partners’ Capital					
Current liabilities					
Accounts payable	$—	$2,571	$ 469	$—	$3,040
Accrued gas purchases	—	8,615	4,297	—	12,912
Risk management liabilities	—	—	—	—	—
Accrued expenses and other current liabilities	—	5,171	36	—	5,207
Total current liabilities	—	16,357	4,802	—	21,159
Other liabilities	—	8,429	455	—	8,884
Long-term debt	—	118,650	—	—	118,650
Total liabilities	—	143,436	5,257	—	148,693
Total partners' capital	90,326	90,325	51,863	(142,188)	90,326
Total liabilities and partners' capital	$90,326	$233,761	$ 57,120	$(142,188)	$239,019
Noncontrolling interest	—	—	7,407	—	7,407
Total liabilities, partners' equity and noncontrolling interest	$90,326	$233,761	$ 64,527	$(142,188)	$246,426

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Condensed Consolidating Statements of Operations
Three months ended September 30, 2012

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(in thousands)				
Revenue	$—	$43,085	$ 15,371	$(370)	$58,086
Unrealized gains (loss) on commodity derivatives	—	(1,762)	—	—	(1,762)
Total revenue	—	41,323	15,371	(370)	56,324
Operating expenses:					
Purchases of natural gas, NGLs and condensate	—	32,729	11,541	(370)	43,900
Direct operating expenses	—	4,286	978	—	5,264
Selling, general and administrative expenses	—	3,583	96	—	3,679
Equity compensation expense	—	474	—	—	474
Depreciation and accretion expense	—	5,134	402	—	5,536
(Gain) loss on sale of assets, net	—	(4)	—	—	(4)
Total operating expenses	—	46,202	13,017	(370)	58,849
Operating income (loss)	—	(4,879)	2,354	—	(2,525)
Other income (expenses):					
Earnings from consolidated affiliates	(4,275)	2,105	—	2,170	—
Interest expense	—	(1,501)	—	—	(1,501)
Net income (loss)	(4,275)	(4,275)	2,354	2,170	(4,026)
Net income (loss) attributable to noncontrolling interests	—	—	249	—	249
Net income (loss) attributable to the Partnership	$(4,275)	$(4,275)	$ 2,105	$2,170	$(4,275)

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Condensed Consolidating Statements of Operations
Nine months ended September 30, 2012

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(in thousands)				
Revenue	$—	$133,362	$ 15,371	$(370)	$148,363
Unrealized gains (loss) on commodity derivatives	—	1,732	—	—	1,732
Total revenue	—	135,094	15,371	(370)	150,095
Operating expenses:					
Purchases of natural gas, NGLs and condensate	—	96,177	11,541	(370)	107,348
Direct operating expenses	—	11,053	978	—	12,031
Selling, general and administrative expenses	—	10,580	96	—	10,676
Equity compensation expense	—	1,272	—	—	1,272
Depreciation and accretion expense	—	15,417	402	—	15,819
(Gain) loss on sale of assets, net	—	(126)	—	—	(126)
Total operating expenses	—	134,373	13,017	(370)	147,020
Operating income (loss)	—	721	2,354	—	3,075
Other income (expenses):					
Earnings from consolidated affiliates	(257)	2,105	—	(1,848)	—
Interest expense	—	(3,083)	—	—	(3,083)
Net income (loss)	(257)	(257)	2,354	(1,848)	(8)
Net income (loss) attributable to noncontrolling interests	—	—	249	—	249
Net income (loss) attributable to the Partnership	$(257)	$(257)	$ 2,105	$(1,848)	$(257)

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Condensed Consolidating Statements of Cash Flows
Nine months ended September 30, 2012

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(in thousands)				
Net cash provided (used) in operating activities	—	14,122	2,354	—	16,476
Cash flows from investing activities					
Cost of acquisition, net of cash acquired	—	(51,377)	—	—	(51,377)
Additions to property, plant and equipment	—	(4,196)	(269)	—	(4,465)
Proceeds from disposals of property, plant and equipment	—	126	—	—	126
Net contributions from affiliates	12,037	—	—	(12,037)	—
Net distributions to affiliates	—	(10,201)	(1,836)	12,037	—
Net cash provided (used) in investing activities	12,037	(65,648)	(2,105)	—	(55,716)
Cash flows from financing activities					
Unit holder contributions	13	—	—	—	13
Unit holder distributions	(12,050)	—	—	—	(12,050)
Net distributions to noncontrolling interest owners	—	—	(249)	—	(249)
LTIP tax netting unit repurchase	—	(88)	—	—	(88)
Deferred debt issuance costs	—	(1,140)	—	—	(1,140)
Payments on long-term debt	—	(42,310)	—	—	(42,310)
Borrowings on long-term debt	—	94,690	—	—	94,690
Net cash provided (used) in financing activities	(12,037)	51,152	(249)	—	38,866
Net increase (decrease) in cash and cash equivalents	—	(374)	—	—	(374)
Cash and cash equivalents					
Beginning of period	1	870	—	—	871
End of period	$1	$496	$ —	$—	$497
Supplemental cash flow information					
Interest payments	$—	$1,894	$ —	$—	$1,894
Supplemental non-cash information					
Increase (decrease) in accrued property, plant and equipment	$—	$808	$ —	$—	$808

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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 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, 2011 included in Annual Report on Form 10-K ("Annual Report") that was filed with the Securities and Exchange Commission (the "SEC") on March 19, 2012. 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" within the meaning of the Private Securities Litigation Reform Act of 1995. 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," "f 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 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;
- weather and other natural phenomena;
- 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 existing and recently acquired assets and our success in connecting natural gas supplies to our gathering and processing systems;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; 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 forward-looking statements are more fully described in "Item 1A. Risk Factors" and elsewhere in this Quarterly Report and our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

Overview

We are a growth-oriented Delaware limited partnership that was formed by affiliates of American Infrastructure MLP Fund, L.P. ("AIM") in August 2009 to own, operate, develop and acquire a diversified portfolio of natural gas midstream energy

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assets. We are engaged in the business of gathering, treating, processing, fractionating and transporting natural gas through our ownership and operation of ten gathering systems, four processing facilities, two interstate pipelines and five intrastate pipelines as of September 30, 2012. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 1,400 miles of pipelines that gather and transport over 500 MMcf/d of natural gas.

Our operations are organized into two segments: (i) Gathering and Processing and (ii) Transmission. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, transporting and treating natural gas. Where we provide processing services at the plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and resulting natural gas liquids (“NGLs”) under POP arrangements. We own four processing facilities that produced an average of approximately 51.9 Mgal/d and 42.8 Mgal/d of gross NGLs and received approximately 7.3 Mgal/d and 11.0 Mgal/d from our 50% interest in Burns Point Plant for the three and nine months ended September 30, 2012. In addition, in connection with our elective processing arrangements, we contract for processing capacity at the Toca plant operated by a subsidiary of Enterprise Products Partners L.P. (“Enterprise”), where we have the option to process natural gas that we purchase. Under these arrangements, we sold an average of approximately 24.8 Mgal/d and 23.5 Mgal/d of net equity NGL volumes for the three and nine months ended September 30, 2012, respectively.

The Toca plant is a cryogenic processing plant with a design capacity of approximately 1.1 Bcf/d that is located in St. Bernard Parish in Louisiana. Under our POP processing contract with Enterprise, we can process raw natural gas through the Toca plant, whether for our customers or our own account. Our month-to-month contracts with producers on the Gloria and Lafitte systems, as well as our ability to purchase natural gas at the Lafitte/TGP interconnect, provide us with the flexibility to decide whether to process natural gas through the Toca plant and capture processing margins for our own account or deliver the natural gas into the interstate pipeline market at the inlet to the Toca plant. We make this decision based on the relative prices of natural gas and NGLs on a monthly basis. We refer to the flexibility built into these contracts as our elective processing arrangements.

We also receive fee-based and fixed-margin compensation in our Transmission segment primarily related to capacity reservation charges under our firm transportation contracts and the transportation of natural gas pursuant to our interruptible transportation and fixed-margin contracts.

Recent Developments

$200 Million Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our $85 million credit facility ("former credit facility") evidenced by our credit agreement with a syndicate of lenders, for which Comerica Bank acted as Administrative Agent, and entered into a $100 million Credit Facility evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto.

In connection with our IPO, we borrowed on the credit facility to (i) make an aggregate distribution of $27.9 million, on a pro rata basis to AIM Midstream Holdings, to participants in our LTIP holding common units and our general partner and (ii) pay fees and expenses of $2.3 million relating to our credit facility. The distribution made to AIM Midstream Holdings and our general partner was a reimbursement for certain capital expenditures incurred with respect to assets previously contributed to us.

On June 27, 2012, we amended our credit facility to increase the Commitments from an aggregate principal amount of $100 million to an aggregate principal amount of $200 million evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto. The credit facility also provides for a $50 million dollar accordion feature. If the accordion feature were to be fully exercised, the total commitment under the existing facility would be $250 million.

Registration statement

On September 11, 2012, we filed a shelf registration statement on Form S-3 with the SEC with a $400 million offering amount. Once effective, the shelf registration statement will allow us to issue additional partnership equity and debt securities.

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Acquisition

During the third quarter of 2012, we announced the closing of the acquisition of an 87.4% undivided interest in the Chatom processing and fractionation plant and associated gathering infrastructure from affiliates of Quantum Resources Management, LLC, effective July 1, 2012. The acquisition consideration of approximately $51.4 million includes a credit to American Midstream for the cash flow Chatom generated between January 1, 2012, and the acquisition effective date, please read Note 3, "Acquisitions".

Chatom is located in Washington County, Alabama, approximately 15 miles from American Midstream's Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 million cubic feet per day refrigeration processing plant, a 1,900 barrel per day fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 29-mile gas gathering system.

Impact of Hurricane Isaac

During the third quarter of 2012, we suspended operations on all gathering and processing systems in Hurricane Isaac's projected path before the hurricane reached the Gulf Coast. The hurricane caused direct damage to the Gloria and Lafitte systems. In addition, the Quivira, Burns Point, and Chalmette systems were indirectly impacted due to customers' production shut-ins. Following the hurricane, we restored operations as quickly as reasonably possible given the magnitude of the storm surge, dependence on third parties to restore power, the availability of construction equipment and crews, and the impact to producer customers' oil and gas production.

We currently estimate expenditures to repair the Gloria and Lafitte systems could exceed approximately $1.4 million, which will be incurred in the third and fourth quarters of 2012. Operating income was negatively impacted by approximately $1.1 million in the third quarter. The systems are insured for named windstorms and business interruption after meeting a $1.0 million deductible.

Our assessment to date has not identified the need to write down property, plant and equipment. Final repairs are nearly complete on our Gulf Coast assets that were damaged during Hurricane Isaac, and gathering and processing volumes have returned to pre-hurricane levels.

Subsequent Events

Distribution

On October 23, 2012, we announced a distribution of $0.4325 per unit payable on November 14, 2012 to unitholders of record on November 7, 2012.

Our Operations

We manage our business and analyze and report our results of operations through two 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, performing fractionation 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.

Gathering and Processing Segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas we gather and process, 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

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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 and NGLs 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 interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our consolidated statement of operations, our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.
- Interest in the Chatom Assets. We account for our 87.4% undivided interest in the Chatom Assets pursuant to 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 consolidated financial statements at the consolidated amounts, which include the amounts attributable to the partners' and the noncontrolling interests. The 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 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 primarily by capacity reservation fees from firm transportation contracts and, to a lesser extent, 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.

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

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trend analysis. These metrics include throughput volumes, gross margin and direct operating expenses on a segment basis, and adjusted EBITDA and distributable cash flow 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 capacity reservation fees, as opposed to the actual 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.

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

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.

Effective April 1, 2011, we changed our gross margin and segment gross margin measure to exclude realized gains and losses associated with the early termination of commodity derivative contracts. For the three and nine months ended September 30, 2012, there were no realized gains (losses) associated with the early termination of commodity derivative contracts.

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

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charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts and selected charges that are unusual or non-recurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, construction, operating and maintenance agreement ("COMA") income, amortization of commodity put purchase costs, and selected gains that are unusual or non-recurring. The GAAP measure most directly comparable to adjusted EBITDA is net income.

We changed our calculation of adjusted EBITDA during 2011 to include the straight-line amortization of commodity put premiums over the life of the associated commodity put contracts. This is necessary as all unrealized commodity gains and losses, by definition, are excluded in calculating adjusted EBITDA and such premium costs would only be included in the calculation of adjusted EBITDA at the expiration of the put contract. We believe this treatment better reflects the allocation of commodity put premium costs over the benefit period of the commodity put contract. Commodity put premium amortization included in the calculation of adjusted EBITDA was less than $0.1 million and $0.3 million for the three and nine months ended September 30, 2012. Further we made a change to the calculation to exclude COMA income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the three and nine months ended September 30, 2012 was $0.8 million and $3.0 million.

Distributable Cash Flow

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder). Distributable cash flow will not reflect changes in working capital balances.

We define distributable cash flow as adjusted EBITDA plus interest income, less cash paid for interest expense, normalized integrity management costs and normalized maintenance capital expenditures.

Note About Non-GAAP Financial Measures

Gross margin, adjusted EBITDA and distributable cash flows are all 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, adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Gross margin, adjusted EBITDA and distributable cash flow 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.

For a reconciliation of gross margin to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 14 to our unaudited consolidated financial statements included in "Item 1. Financial Statements" of this Quarterly Report.

The following tables reconcile the non-GAAP financial measures, adjusted EBITDA and distributable cash flow, used by management to their most directly comparable GAAP measures for the three and nine months ended September 30, 2012 and 2011:

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	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income (loss) attributable to the Partnership	$(4,275)	$(4,167)	$(257)	$(11,859)
Add:				
Depreciation and accretion expense	5,536	5,261	15,819	15,468
Interest expense	1,501	1,378	3,083	3,923
Realized gain (loss) on early termination of commodity derivatives	—	—	—	2,998
Unrealized (gain) loss on commodity derivatives	1,762	(953)	(1,732)	19
Non-cash equity compensation expense	474	331	1,272	1,234
Advisory services agreement termination fee	—	2,500	—	2,500
Special distribution to holders of LTIP phantom units	—	—	—	1,624
Transaction expenses	—	—	—	281
Deduct:				
COMA income	819	127	2,980	379
Straight-line amortization of put costs (1)	46	111	269	297
OPEB plan net periodic benefit (cost)	23	—	64	—
Gain (loss) on sale of assets, net	4	586	126	586
Adjusted EBITDA	$4,106	$3,526	$14,746	$14,926
Deduct:				
Cash interest expense (2)	$1,292	$646	$2,590	$2,802
Normalized maintenance capital (3)	1,041	750	2,791	2,250
Normalized integrity management (4)	(58)	375	692	1,125
Distributable Cash Flow	$1,831	$1,755	$8,673	$8,749

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

(2) Excludes amortization of debt issuance costs and mark-to-market adjustments related to interest rate derivatives.

(3) Amounts noted represent estimated annual maintenance capital expenditures of $3.8 million which is what we expect to be required to maintain our assets over the long term.

(4) Amounts noted represent average estimated integrity management costs over the seven year mandatory testing cycle net of integrity management costs that are expensed in Selling, general and administrative expenses.

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 the Annual Report.

We believe the diversity of our assets and our hedged commodity position to protect against downside commodity risk are key elements to long-term growth and sustainable distributable cash flow.

We continue to actively manage our capital maintenance and capital program. On August 13, 2012, we announced a growth project and expect to construct a midstream system to gather, treat, compress and process natural gas from wells targeting multiple liquids-rich producing formations, including the Eaglebine Formation. The anticipated midstream system would include up to 60 million cubic feet per day of gathering and processing capacity to support customers' production as well as other third-party development in the area. We expect to complete construction on the initial phase of the midstream infrastructure and begin operations in early 2013.

In our Gathering and Processing segment, favorable oil prices are supporting drilling activity in the liquids-rich Upper Smackover formation, which continues to benefit our Bazor Ridge and Chatom systems. In our Transmission segment, as a result of lower natural gas prices, we have seen increased interest from the industrial and utility markets in northern Alabama

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and southwestern Mississippi, which we believe will positively impact our AlaTenn and Midla systems.
Credit markets continue to experience near-record lows, which we believe will continue through 2012; however, if monetary policy begins to tighten, our interest rates on floating rate debt facilities and future offerings in the debt capital markets could be higher. An increase in financing costs may affect yield requirements of investors who invest in our common units.
Our expectations are based on assumptions we made and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.
Results of Operations — Combined Overview
Our distributable cash flow for the third quarter 2012 was $1.8 million, which was no change from third quarter 2011. For the third quarter 2012, gross margin increased $4.6 million from that of the third quarter 2011, from $9.6 million to $14.2 million.
The following table and discussion presents certain of our historical consolidated financial data for the periods indicated. The results of operations by segment are discussed in further detail following this combined overview.

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Statement of Operations Data:				
Revenue	$58,086	$57,005	$148,363	$190,374
Realized gain (loss) on early termination of commodity derivatives	—	—	—	(2,998)
Unrealized gain (loss) on commodity derivatives	(1,762)	953	1,732	(19)
Total revenue	56,324	57,958	150,095	187,357
Operating expenses				
Purchases of natural gas, NGLs and condensate	43,900	47,359	107,348	157,725
Direct operating expenses	5,264	3,385	12,031	9,548
Selling, general and administrative expenses	3,679	2,497	10,676	7,649
Transaction expenses	—	2,500	—	2,500
Equity compensation expense (a)	474	331	1,272	2,989
Depreciation and accretion expense	5,536	5,261	15,819	15,468
(Gain) loss on sale of assets, net	(4)	(586)	(126)	(586)
Total operating expenses	58,849	60,747	147,020	195,293
Operating income (loss)	(2,525)	(2,789)	3,075	(7,936)
Interest expense	(1,501)	(1,378)	(3,083)	(3,923)
Net income (loss)	$(4,026)	$(4,167)	$(8)	$(11,859)
Net income (loss) attributable to noncontrolling interests	249	—	249	—
Net income (loss) attributable to the Partnership	(4,275)	(4,167)	(257)	(11,859)
Other Financial Data:				
Gross margin (b)	$14,186	$9,646	$41,015	$32,649
Adjusted EBITDA (c)	$4,106	$3,526	$14,746	$14,926
Distributable cash flow (d)	$1,831	$1,755	$8,673	$8,749

(a) Represents cash and non-cash costs related to our LTIP. Of these amounts, $0.5 million and $0.3 million, for the three months ended September 30, 2012 and 2011, respectively, and $1.3 million and $1.2 million, for the nine months ended September 30, 2012 and 2011, respectively, were non-cash expenses.
(b) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 14 to our unaudited condensed consolidated financial

statements included in this Quarterly Report for a discussion of how we use gross margin to evaluate our operating performance.

(c) For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated

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and presented in accordance with GAAP and a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read "—How We Evaluate Our Operations".

(d) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use distributable cash flow to evaluate our operating performance, please read "—How We Evaluate Our Operations".

Three months ended September 30, 2012 Compared to Three months ended September 30, 2011

Revenue. Our total revenue in the three months ended September 30, 2012 was $56.3 million compared to $58.0 million in the three months ended September 30, 2011. The decrease of $1.7 million was primarily due to increased condensate volumes, increased NGL production volumes and throughput offset by lower realized natural gas prices in both our Gathering and Processing and Transmission segments, and lower realized NGL prices in our Gathering and Processing segment. In addition:

- Condensate volumes were the primary reason for the increase in our revenues, as our condensate volumes increased approximately 3.7 million gallons in the third quarter 2012 over the same period in 2011 due to the newly acquired Chatom Assets. Although impacted by Hurricane Isaac, gross NGL production increased to 59.2 Mgal/d due to the newly acquired Chatom Assets offset by lower realized NGL prices, which were approximately 32% lower in the third quarter 2012 than the third quarter 2011.
- We entered into a series of swap, collar and put contracts during the three months ended September 30, 2012. These commodity derivative transactions had a negative net effect of $(1.8) million on our revenue related to unrealized loss for the three months ended September 30, 2012. For the three months ended September 30, 2011 we recognized an unrealized valuation gain of $1.0 million related to commodity derivative contracts. For a discussion of our commodity derivative positions, please read "Item 3. Quantitative and Qualitative Disclosures about Market Risk." Unrealized gain (loss) on commodity derivatives are not included in Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended September 30, 2012 were $43.9 million compared to $47.4 million in the three months ended September 30, 2011. This decrease of $3.5 million was primarily due to lower realized natural gas and NGL prices offset by an increase in the purchase of condensate volumes as a result of our acquisition of the Chatom Assets, effective July 1, 2012, in our Gathering and Processing segment and lower realized natural gas prices in our Transmission segment. Our natural gas purchases related to our fixed margin contracts and the allocated natural gas proceeds related to our POP agreements are based on the same indexes as the corresponding natural gas sales, so we saw a similar decrease in the price which we paid to purchase natural gas as we did to sell it. We also saw decreased NGL costs associated with the allocated proceeds of NGL revenue related to our POP agreements.

Gross Margin. Gross margin in the three months ended September 30, 2012 was $14.2 million compared to $9.6 million in the three months ended September 30, 2011. This increased of $4.6 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011 and gross margin from our newly acquired 87.4% undivided interest in the Chatom Assets effective July 1, 2012. The increase was partially offset by lower gross margin at processing plants owned by the Partnership due to lower realized NGL prices, and lower throughput volumes and NGL production on several assets in the Gathering and Processing segment, including lower volumes resulting from Hurricane Isaac.

Direct Operating Expenses. Direct operating expenses in the three months ended September 30, 2012 were $5.3 million compared to $3.4 million in the three months ended September 30, 2011. This increase of $1.9 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011 and our interest in the Chatom Assets effective July 1, 2012. Incremental direct operating expenses of $0.3 million were associated with repairs as a result of reconnecting our facilities due to Hurricane Isaac.

Selling, General and Administrative Expenses. SG&A expenses in the three months ended September 30, 2012 were $3.7 million compared to $2.5 million in the three months ended September 30, 2011. This increase of $1.2 million was primarily due to $0.5 million in increased costs associated with operating as a publicly traded company, increased integrity management costs of $0.4 million and increased payroll costs of $0.3 million.

Equity Compensation Expense. Compensation expense in the three months ended September 30, 2012 was $0.5 million compared to $0.3 million in the three months ended September 30, 2011. This increase of $0.2 million was primarily due to the amortization associated with new LTIP grants in April and July 2012.

Depreciation Expense. Depreciation expense in the three months ended September 30, 2012 was $5.5 million compared to $5.3 million in the three months ended September 30, 2011. This increase of $0.2 million was due to the newly acquired long-

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lived assets associated with the Chatom Assets.

Nine months ended September 30, 2012 Compared to Nine months ended September 30, 2011

Revenue. Our total revenue in the nine months ended September 30, 2012 was $150.1 million compared to $187.4 million in the nine months ended September 30, 2011. The decrease of $37.3 million was primarily due to lower realized natural gas prices and natural gas sales volumes in both our Gathering and Processing and Transmission segments offset by an increase in condensate volumes. In addition:

- Natural gas prices were the primary reason for the decrease in our revenues, as our realized natural gas prices were approximately 36% lower in the nine months ended September 30, 2012 than over the same period in 2011. Natural gas sales volumes decreased due to new volumes gathered and transported under transportation agreements instead of fixed margin contracts. Revenues were also lower due to lower realized NGL prices in our Gathering and Processing segment. Realized NGL prices were approximately 17% lower in the nine months ended September 30, 2012 than the nine months ended September 30, 2011.
- We entered into a series of swap, collar and put contracts during the nine months ended September 30, 2012. These commodity derivative transactions had a positive net effect of $1.7 million on our revenue related to unrealized gains for the nine months ended September 30, 2012. For the nine months ended September 30, 2011 we recognized an unrealized valuation loss of less than $0.1 million related to commodity derivative contracts and $3.0 million for loss on early termination of commodity derivative contracts, For a discussion of our commodity derivative positions, please read “Item 3. Quantitative and Qualitative Disclosures about Market Risk.” Unrealized gain (loss) on commodity derivatives are not included in Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the nine months ended September 30, 2012 were $107.3 million compared to $157.7 million in the nine months ended September 30, 2011. This decrease of $50.4 million was primarily due to lower realized natural gas prices and lower natural gas purchase volumes in our Gathering and Processing and Transmission segments. Purchases of natural gas, NGLs and condensate were also lower due to lower realized NGL prices which decreased our NGL costs related to our POP agreements in our Gathering and Processing segment partially offset by our increase in condensate purchases associated with our acquisition of the Chatom Assets, effectively July 1, 2012. Our natural gas purchases related to our fixed margin contracts and the allocated natural gas proceeds related to our POP agreements are based on the same indexes as the corresponding natural gas sales, so we saw a similar decrease in the price, which we paid to purchase natural gas as we did to sell it. Natural gas purchase volumes decreased due to lower throughput and new volumes gathered and transported under transportation agreements instead of fixed margin contracts.

Gross Margin. Gross margin in the nine months ended September 30, 2012 was $41.0 million compared to $32.6 million in the nine months ended September 30, 2011. This increase of $8.4 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011, gross margin from our newly acquired interest in the Chatom Assets effective July 1, 2012, and higher revenues associated with reimbursable projects in our Transmission and Gathering and Processing segments. The increase was partially offset by lower gross margin at processing plants owned by the Partnership due to lower realized NGL prices, and lower throughput volumes and NGL production on several assets in the Gathering and Processing segment, including lower volumes resulting from Hurricane Isaac.

Direct Operating Expenses. Direct operating expenses in the nine months ended September 30, 2012 were $12.0 million compared to $9.5 million in the nine months ended September 30, 2011. This increase of $2.5 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011 and our interest in the Chatom Assets, offset by reduction in spending related to consulting fees and supplies. Incremental direct operating expenses of $0.5 million were associated with repairs as a result of facility damage due to Hurricane Isaac.

Selling, General and Administrative Expenses. SG&A expenses in the nine months ended September 30, 2012 were $10.7 million compared to $7.6 million in the nine months ended September 30, 2011. This increase of $3.1 million was primarily due to increased integrity management costs of $0.6 million, increased payroll costs of $1.2 million and $1.2 million in increased costs associated with operating as a publicly traded company.

Equity Compensation Expense. Compensation expense in the nine months ended September 30, 2012 was $1.3 million compared to $3.0 million in the nine months ended September 30, 2011. This decrease of $1.7 million was primarily due to the elimination of DER payments in the second quarter of 2011 associated with our LTIP, offset by an increase of $0.2 million related to the amortization associated with new LTIP grants in April and July 2012.

Depreciation Expense. Depreciation expense in the nine months ended September 30, 2012 was $15.8 million compared to $15.5 million in the nine months ended September 30, 2011. This increase of $0.3 million was due to depreciation associated with capital projects placed into service during the period, in addition to depreciation associated with our acquisition of our

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interests in the Burns Point processing plant, which was effective November 1, 2011 and the Chatom Assets, which was effective July 1, 2012.

Results of Operations — Segment Results

The table below contains key segment performance indicators related to our segment results of operations.

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
	(in thousands except operational data)			
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$45,376	$41,218	$111,246	$138,487
Realized gain (loss) on early termination of commodity derivatives	—	—	—	(2,998)
Unrealized gain (loss) on commodity derivatives	(1,762)	953	1,732	(19)
Total revenue	43,614	42,171	112,978	135,470
Purchases of natural gas, NGLs and condensate	$34,640	$34,398	$82,048	$115,500
Direct operating expenses	$3,935	$1,845	$8,495	$5,478
Other financial data:				
Segment gross margin	$10,736	$6,821	$29,198	$22,988
Operating data:				
Average throughput (MMcf/d)	245.4	209.0	318.6	227.6
Average plant inlet volume (MMcf/d) (a) (b)	99.8	15.2	130.4	14.9
Average gross NGL production (Mgal/d) (a) (c)	59.2	52.0	53.8	51.7
Average realized prices:				
Natural gas ($/MMcf)	$3.05	$4.35	$2.73	$4.26
NGLs ($/gal)	$0.94	$1.38	$1.12	$1.35
Condensate ($/gal)	$2.27	$2.31	$2.33	$2.36
Transmission segment				
Financial data:				
Total revenue	$12,710	$15,787	$37,117	$51,887
Purchases of natural gas, NGLs and condensate	$9,260	$12,961	$25,300	$42,225
Direct operating expenses	$1,329	$1,540	$3,536	$4,070
Other financial data:				
Segment gross margin	$3,450	$2,825	$11,817	$9,661
Operating data:				
Average throughput (MMcf/d)	427.8	373.6	409.7	377.7
Average firm transportation - capacity reservation (MMcf/d)	655.6	655.7	692.7	693.0
Average interruptible transportation - throughput (MMcf/d)	98.5	68.2	77.6	72.5

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

Three months ended September 30, 2012 Compared to Three months ended September 30, 2011

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Gathering and Processing Segment

Revenue. Segment total revenue in the three months ended September 30, 2012 was $43.6 million compared to $42.2 million in the three months ended September 30, 2011. This increase of $1.4 million was, in part, due to an increase in condensate and NGL production volumes at our newly acquired Chatom Asset offset by lower realized natural gas prices and lower natural gas sales volumes on several of our systems as a result of Hurricane Isaac. In addition:

- Total natural gas throughput volumes on our Gathering and Processing segment were 245.4 MMcf/d in the three months ended September 30, 2012 compared to 209.0 MMcf/d in the three months ended September 30, 2011. Natural gas inlet volumes at our owned processing plants were 99.8 MMcf/d in the three months ended September 30, 2012 compared to 15.2 MMcf/d in the three months ended September 30, 2011. The natural gas throughput and inlet volume increases are primarily related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011. Also, one of our systems saw a decline in volumes during the third quarter as a result of a producer customer completing work on their platforms. We are working with this producer customer to return volumes on our system to historical levels, although the contract terms may change for a portion of the volumes going forward and a change in contract terms may have a material impact on our financial results. The average realized price of natural gas in the three months ended September 30, 2012 was $3.05/Mcf, compared to $4.35/Mcf in the three months ended September 30, 2011.
- Gross NGL production volumes from our owned processing plants were 59.2 Mgal/d in the three months ended September 30, 2012 compared to 52.0 Mgal/d in the three months ended September 30, 2011. NGL production volumes were slightly higher from prior year due to incremental NGL production related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011 and our newly acquired Chatom Assets, effective July 1, 2012, offset in part, by lower NGL production at our Bazor Ridge gathering and processing facility. The average realized price of NGLs in the three months ended September 30, 2012 was $0.94/gal, compared to $1.38/gal in the three months ended September 30, 2011.
- Gross condensate volumes were 45.9 Mgal/d in the three months ended September 30, 2012 compared to 5.8 Mgal/d in September 30, 2011. The average realized price of condensate in the three months ended September 30, 2012 was $2.27/gal, compared to $2.31/gal in the three months ended September 30, 2011.
- We entered into a series of swap, collar and put contracts during the three months ended September 30, 2012. These commodity derivative transactions had a negative net effect of $(1.8) million on our revenue related to unrealized gains for the three months ended September 30, 2012. For the three months ended September 30, 2011 we recognized an unrealized valuation gain of $1.0 million related to commodity derivative contracts. For a discussion of our commodity derivative positions, please read “Item 3. Quantitative and Qualitative Disclosures about Market Risk.” Unrealized gain (loss) on commodity derivatives are not included in Segment Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended September 30, 2012 were $34.6 million compared to $34.4 million in the three months ended September 30, 2011. Before the effect of the acquisitions, this increase of $0.2 million was primarily due to lower natural gas sales prices, which decreased natural gas costs associated with our fixed margin and POP agreements, and lower natural gas purchase volumes due to less volume gathered under fixed margin contracts offset by increases in purchases of condensate as a result of the newly acquired Chatom Assets, effectively July 1, 2012. NGL purchase costs associated with our POP agreements at Bazor Ridge were also lower due to lower realized NGL prices and lower NGL volumes.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2012 was $10.7 million compared to $6.8 million for the three months ended September 30, 2011. This increase of $3.9 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011and gross margin from our newly acquired interest in the Chatom Assets effective July 1, 2012. The increase was partially offset by lower gross margin at processing plants owned by the Partnership due to lower realized NGL prices, and lower throughput volumes and NGL production on several assets in the Gathering and Processing segment, including lower volumes resulting from Hurricane Isaac.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2012 were $3.9 million compared to $1.8 million for the three months ended September 30, 2011. This increase of $2.1 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011 and our interest in the Chatom Assets effective July 1, 2012. Incremental direct operating expenses of $0.5 million were associated with repairs as a result of facility damage due to Hurricane Isaac.

Transmission Segment

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Revenue. Segment total revenue for the three months ended September 30, 2012 was $12.7 million compared to $15.8 million for the three months ended September 30, 2011. This decrease of $3.1 million in revenue was primarily due to lower realized natural gas prices, which negatively impacted revenues associated with our fixed margin agreements on MLGT and Midla. Total natural gas throughput on our Transmission systems for the three months ended September 30, 2012 was 427.8 MMcf/d compared to 373.6 MMcf/d in the three months ended September 30, 2011. The increase in throughput is primarily a result of higher demand on our Bamagas system and new production on a section of our Midla system. Segment revenues associated with Bamagas and Midla systems are predominately contracted as Firm Transportation in nature and therefore incremental throughput generally does not result in material incremental segment revenues.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended September 30, 2012 were $9.3 million compared to $13.0 million for the three months ended September 30, 2011. This decrease of $3.7 million was primarily due to lower realized natural gas prices, which resulted in lower natural gas purchase costs associated with our fixed margin agreements on MLGT and Midla.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2012 was $3.5 million compared to $2.8 million for the three months ended September 30, 2011. This increase of $0.7 million was primarily due to higher revenues from reimbursable projects.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2012 were $1.3 million compared to $1.5 million for the three months ended September 30, 2011, with a net decrease of $0.2 million. There were no significant changes in any individual expense type.

Nine months ended September 30, 2012 Compared to Nine months ended September 30, 2011

Gathering and Processing Segment

Revenue. Segment total revenue in the nine months ended September 30, 2012 was $113.0 million compared to $135.5 million in the nine months ended September 30, 2011. This decrease of $22.5 million was primarily, in part, due to lower realized natural gas prices and lower natural gas sales volumes, primarily on our Gloria system, due to increased fee based transportation volumes and lower overall throughput volume. In addition:

- Revenues also decreased as a result of lower NGL sales volumes associated with our elective processing arrangement on the Gloria system associated with lower throughput volumes, higher fee-based contract volumes, and increased deliveries to on-system markets as well as lower NGL production at our Bazor Ridge processing plant as work was done on the plant’s gas-to-gas exchanger. Revenues were also lower as a result of lower realized NGL sales prices partially offset by higher condensate sales volumes related to the our newly acquired Chatom Assets.
- Total natural gas throughput volumes on our Gathering and Processing segment were 318.6 MMcf/d in the nine months ended September 30, 2012 compared to 227.6 MMcf/d in the nine months ended September 30, 2011. Natural gas inlet volumes at our owned processing plants were 130.4 MMcf/d in the nine months ended September 30, 2012 compared to 14.9 MMcf/d in the nine months ended September 30, 2011. The natural gas throughput and inlet volume increases are primarily related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011 and our undivided interest in the Chatom Assets, effective July 1, 2012. Gross NGL production volumes from our owned processing plants were 53.8 Mgal/d in the nine months ended September 30, 2012 compared to 51.7 Mgal/d in the nine months ended September 30, 2011. NGL production volumes were slightly higher from prior year due to an increase related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011 and our 87.4% undivided interest in the Chatom Assets, effective July 1, 2012, offset in part, by lower NGL production at our Bazor Ridge gathering and processing facility. The average realized price of natural gas in the nine months ended September 30, 2012 was $2.73/Mcf, compared to $4.26/Mcf in the nine months ended September 30, 2011. The average realized price of NGLs in the nine months ended September 30, 2012 was $1.12/gal, compared to $1.35/gal in the nine months ended September 30, 2011. The average realized price of condensate in the nine months ended September 30, 2012 was $2.33/gal, compared to $2.36/gal in the nine months ended September 30, 2011.
- We entered into a series of swap, collar and put contracts during the nine months ended September 30, 2012. These commodity derivative transactions had a positive net effect of $1.7 million on our revenue related to unrealized gains for the nine months ended September 30, 2012. For the nine months ended September 30, 2011 we recognized an unrealized valuation loss of less than $0.1 million related to commodity derivative contracts. For a discussion of our

commodity derivative positions, please read “Item 3. Quantitative and Qualitative Disclosures about Market Risk.” Unrealized gain (loss) on commodity derivatives are not included in Segment Gross Margin.

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Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the nine months ended September 30, 2012 were $82.0 million compared to $115.5 million in the nine months ended September 30, 2011. This decrease of $33.5 million was primarily due to lower natural gas sales prices, which decreased natural gas costs associated with our fixed margin and POP agreements, and lower natural gas purchase volumes due to lower throughput and less volume gathered under fixed margin contracts partially offset by our increase in condensate purchases associated with our acquisition of the Chatom Assets, effectively July 1, 2012. NGL purchase costs associated with our POP agreements at the Bazor Ridge system were also lower due to lower realized NGL prices and lower NGL volumes, before the effects of the acquisitions.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2012 was $29.2 million compared to $23.0 million for the nine months ended September 30, 2011. This increase of $6.2 million was primarily due to the gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011, gross margin from our newly acquired interest in the Chatom Assets effective July 1, 2012 and higher revenues associated with reimbursable projects. This increase was partially offset by lower gross margin at our owned processing plants, primarily Bazor Ridge, as a result of lower natural gas and NGL prices which directly impact margins associated with our POP processing agreements, lower elective processing volumes on our Gloria system, and lower throughput volumes on several of our systems, primarily our Quivira and several of our smaller gathering and processing systems. Elective processing volumes on our Gloria system were lower as a result of higher sales volumes to on-system customers, up stream of the TOCA processing plant, and increased volumes gathered under fee based transportation agreements, under which we earn a lower margin. Volumes on Quivira were lower as a result of compressor restrictions and decline in volumes during the third quarter as a result of a producer customer completing work on their platforms.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2012 were $8.5 million compared to $5.5 million for the nine months ended September 30, 2011. This increase of $3.0 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011 and our interest in the Chatom Assets effective July 1, 2012. Incremental direct operating expenses of $0.5 million were associated with repairs as a result of facility damage due to Hurricane Isaac and additional consulting services incurred of $0.4 million.

Transmission Segment

Revenue. Segment total revenue for the nine months ended September 30, 2012 was $37.1 million compared to $51.9 million for the nine months ended September 30, 2011. This decrease of $14.8 million in revenue was primarily due to lower realized natural gas prices, which negatively impacted revenues associated with our fixed margin agreements on MLGT and Midla, and the conversion of a fixed margin contract to a transportation agreement on our MLGT system. This decrease was partially offset by higher revenues from reimbursable projects. Total natural gas throughput on our Transmission systems for the nine months ended September 30, 2012 was 409.7 MMcf/d compared to 377.7 MMcf/d in the nine months ended September 30, 2011. The increase in throughput is primarily a result of higher demand on our Bamagas system.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the nine months ended September 30, 2012 were $25.3 million compared to $42.2 million for the nine months ended September 30, 2011. This decrease of $16.9 million was primarily due to lower realized natural gas prices, which resulted in lower natural gas purchase costs associated with our fixed-margin agreements on MLGT and Midla, and the conversion of a fixed margin contract to a transportation agreement on our MLGT system.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2012 was $11.8 million compared to $9.7 million for the nine months ended September 30, 2011. This increase of $2.1 million was primarily due to higher revenues from reimbursable projects.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2012 were $3.5 million compared to $4.1 million for the nine months ended September 30, 2011, with a net decrease of $0.6 million. There were no significant changes in any individual expense type.

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 liquidity at September 30, 2012 were our cash on hand and availability under our credit facility

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as discussed below. As of September 30, 2012, we had cash on hand of $0.5 million and $118.7 million borrowed under our credit facility. As of September 30, 2012, our available liquidity was $5.4 million.
We are required to comply with certain financial covenants and ratios in our credit facility. As of September 30, 2012, our leverage ratio, one of the primary financial covenants that we are required to maintain under our credit facility (see Note 8 to our consolidated financial statements included elsewhere in this report), was 4.31. Our credit facility requires that our leverage ratio not exceed 4.50. Our ability to comply with these covenants and ratios in the future will be affected by the levels of debt and of cash flow from our operations, among other factors.

In order to remain in compliance with our financial covenants and ratios under our credit facility, we believe that we have several options available to us that we may pursue separately or in combination. First, subject to market conditions, we have the ability to issue debt or equity securities to refinance or pay down outstanding borrowings under our credit facility and to fund future growth capital expenditures. Second, we may request a waiver from the lenders in our credit facility. Third, we may seek to reduce our debt by amounts that exceed our operating cash flows through actions such as a reduction in capital expenditures; suspension of our quarterly distributions to subordinated unitholders and, thereafter, unitholders; the sale of assets; further reduction of operating and administrative costs; or other steps to enhance liquidity and reduce debt and avoid default.

If we were not in compliance with the financial covenants in the credit facility, or if we did not enter into an agreement to refinance or extend the due date on the credit facility, our debt could become due and payable upon acceleration by the lenders in our banking group. In addition, failure to comply with any of the covenants under our credit facility could adversely affect our ability to fund ongoing operations and growth capital requirements as well as our ability to pay distributions to our unitholders.

Working Capital
Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by 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 $3.0 million at September 30, 2012.
Cash Flows
The following table reflects cash flows for the applicable periods:

	Nine months ended September 30,	
	2012	2011
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$16,476	$7,099
Investing activities	(55,716)	(4,765)
Financing activities	38,866	(1,867)

Nine months ended September 30, 2012 Compared to Nine months ended September 30, 2011
Operating Activities. Net cash provided by operating activities was $16.5 million for the nine months ended September 30, 2012 compared to $7.1 million for the nine months ended September 30, 2011. The change in cash provided by operating activities was primarily a result of the acquisitions of Burns Point effective November 1, 2011 and the Chatom Assets effective July 1, 2012. We received $1.6 million associated with the settlement of net hedges

on our NGL production.
Investing Activities. Net cash used in investing activities was $55.7 million for the nine months ended September 30, 2012

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compared to $4.8 million for the nine months ended September 30, 2011. The change in cash used in investing activities was primarily a result of $51.4 million used to fund the acquisition of the Chatom Assets, which closed in the third quarter of 2012 and $1.0 million related to 2012 capital projects for compressor overhauls at Bazor Ridge and Gloria, interconnections at Gloria, and replacement of gas exchanger at Bazor Ridge.

Financing Activities. Net cash provided in financing activities was $38.9 million for the nine months ended September 30, 2012 compared to net cash used of $1.9 million for the nine months ended September 30, 2011. The change in cash provided in financing activities was primarily a result of the debt borrowing associated with the acquisition of the Chatom Assets offset by repayment activity in 2012.

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:

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

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 year ended December 31, 2011, our capital expenditures exclusive of our purchase of the 50% undivided interest in the Burns Point Plant totaled $6.4 million including expansion capital expenditures of $0.5 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 $3.8 million.

For the three and nine months ended September 30, 2012, our capital expenditures totaled $2.1 million and $4.5 million, including reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of less than $0.1 million and $0.3 million, maintenance capital expenditures of $0.6 million and $2.5 million and expansion capital project expenditures of $1.4 million and $1.6 million, respectively. We anticipate that we will continue to make significant expansion capital expenditures in the future. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future expansion capital expenditures will be funded primarily by borrowings under our credit facility and the issuance of debt and equity securities.

Integrity Management

When we acquired certain operating assets, we inherited an ongoing integrity management program required 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 current program will be completed in 2012. In connection with the acquisition of our assets from the seller we initiated a comprehensive review of the program and concluded that there were sixteen high consequence areas, or HCAs, in addition to those identified by our Predecessor (Enbridge Midcoast Energy, L.P.) that required further testing pursuant to DOT regulations. We expect to incur $0.1 million in integrity management expenses in 2012 associated with these HCAs to complete the current integrity management program.

In 2013 we will begin a new integrity management program during which we expect to incur an average of $1.5 million in integrity management expenses per year over the course of the seven-year cycle.

Because DOT regulations require integrity management activities for each HCA to be performed within seven years from when they were last performed, we expect to incur the following expenses in conjunction with the commencement of our next seven-year integrity management program cycle in 2013:

Integrity Management Expense

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(in thousands)

Total	2013	2014	2015	2016	2017	2018	2019
$10,609	$2,000	$5,015	$839	$675	$—	$—	$2,080

Impact of Bazor Ridge Emissions Matter

In July 2011, in the course of preparing our annual filing for 2010 with the Mississippi Department of Environmental Quality ("MDEQ") as required by our Title V Air Permit, we determined that we underreported to the MDEQ the SO2 (sulfur dioxide) emissions from the Bazor Ridge plant for 2009 and 2010. In addition, we determined that certain SO2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act, or EPCRA, requiring notification of various governmental authorities. We did not make any such EPCRA notifications.

In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO2 emissions. The MDEQ is currently processing this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. We have responded to this Information Request.

Although these current negotiations with the MDEQ and EPA are proceeding towards completion, either agency could initiate further enforcement proceedings with respect to these matters, which could result in additional monetary sanctions and our Bazor Ridge plant could become subject to significant restrictions or limitations on its operations. If the Bazor Ridge plant were subject to any curtailment or other operational restrictions as a result of any such enforcement proceeding, or were required to incur additional capital expenditures for additional emission controls through any permitting process, the costs to us could be material. In addition, if emission levels for our Bazor Ridge plant were not properly reported by the prior owner for periods before our acquisition, it is possible, though not probable at this time, that one or both of the MDEQ and the EPA may institute enforcement actions against us and/or the prior owner, in which case we may have an obligation under our purchase agreement with the prior owner to indemnify them for any resulting losses (as defined in the purchase agreement). We cannot estimate the likelihood or financial impact from any further enforcement proceedings at this time, and therefore we have not recorded a loss contingency as the criteria under ASC 450, Contingencies, has not been met.

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 November 14, 2012, we will pay a distribution for the third quarter 2012 of $0.4325 per unit, or $4.0 million.

Contractual Obligations

The table below summarizes our obligations and other commitments as of September 30, 2012.

	Payments Due by Period (in thousands)						
	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases and service contract	$2,282	$99	$416	$423	$400	$156	$788
Asset retirement obligation	8,559	—	—	—	—	8,107	452
Total	$10,841	$99	$416	$423	$400	$8,263	$1,240

Critical Accounting Policies

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

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11 Disclosures about Offsetting Assets and Liabilities. The ASU requires additional disclosures about the impact of offsetting, or netting, on a company's financial position, and is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods, and retrospectively for all comparative periods presented. Under GAAP, derivative assets and liabilities can be offset under certain conditions. The ASU requires disclosures showing both gross information and net information about instruments eligible for offset in the balance

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sheet. Except for additional disclosures related to our offsetting arrangements, the adoption of the amended guidance is not expected to have a material effect on the Partnership's consolidated financial statements.

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. There have been no material changes to that information. Also, see Note 5 to the unaudited consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

We continually and proactively monitor our commodity exposure and compare this exposure to our stated hedging strategy. In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from canceling our then-existing swap contracts and entering into a new swap contract with an existing counterparty that extends through the end of 2012. We did not modify the put contracts we entered into through our January 2011 hedge transactions.

During the nine months ended September 30, 2012 and 2011, we entered into various commodity swap, option, and collar arrangements.

As of September 30, 2012, we have hedged approximately 63% of our expected exposure to commodity prices for the remainder of 2012 and 2013.

The table below sets forth certain information regarding the financial instruments used to hedge of commodity price risk as of September 30, 2012:

Commodity	Instrument	Notional Volumes	Average Price	Period	Fair Value at September 30, 2012
Natural Gas (Mmbtu)					(in thousands)
	Swaps	(748,000)	$ 3.59	Oct 2012 - Dec 2013	$ (100.4)
NGLs (gals)					
	Swaps	(4,304,000)	0.96	Oct 2012 - Dec 2013	1,752.1
	Puts	(1,061,000)	1.18	Oct 2012 - Dec 2013	61.5
	Collars	(1,086,000)	0.49	Oct 2012 - Dec 2013	14.8
Oil (bbls)					
	Swaps	(93,000)	105.78	Oct 2012 - Dec 2013	(174.9)
					$ 1,553.1

Interest Rate Risk

During the nine months ended September 30, 2012, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. Our interest rate cap contracts that limited our interest rate exposure to 4% expired on December 2, 2011. We currently do not anticipate entering into any interest rate hedging contracts at this time, but changing market conditions may require interest rate hedging contracts to mitigate our exposure to interest rate risk. The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten further, 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 $0.6 million for the nine months ended September 30, 2012.

Item 4. Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner’s President and Chief Executive Officer (our principal executive officer) and our general partner’s Senior Vice President & Chief Financial

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Officer (our principal financial officer), as appropriate, to allow for timely decisions regarding required disclosure. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act of 1934 (the “Exchange Act”)) was performed as of September 30, 2012. This evaluation was performed by our management, with the participation of our general partner’s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer. Based on this evaluation, our general partner’s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer concluded that these disclosure controls and procedures are effective to ensure that we are able to collect, process and disclose the information we are required to disclose in the reports we file with the SEC within the required time periods.

Changes in internal control

No changes in our internal control over financial reporting occurred during the quarter ended September 30, 2012 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 President and Chief Executive Officer and Senior Vice President & Chief 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 not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. 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

In addition to the other information set forth in this Quarterly Report, careful consideration should be given to the risk factors discussed under the caption "Risk Factors" in the Annual Report and below in this Quarterly Report.

Risks Related to Financing and Credit Environment

Our credit facility includes financial covenants and ratios. We may have difficulty maintaining compliance with the financial covenants, which include a maximum leverage ratio of 4.50 on a quarterly basis, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We depend on our credit facility for future capital needs and to fund a portion of cash distributions to unitholders, as necessary. We are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. Our failure to comply with any of the covenants under our credit facility could result in a default, which could cause all of our existing indebtedness to become immediately due and payable.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

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Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	Second Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
3.3	Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.5 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.5	First Amendment to Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
10.1	Second Amended and Restated American Midstream GP, LLC Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report in Form 8-K (Commission File No. 001-35257) filed on July 17, 2012).
31.1*	Certification of Brian F. Bierbach, President and Chief Executive Officer of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the September 30, 2012 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 September 30, 2012 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Brian F. Bierbach, President and Chief Executive Officer of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the September 30, 2012 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 September 30, 2012 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith
**	Submitted electronically herewith. Pursuant to Rule 406T of Regulation S-T, the interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement of prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not files for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended and otherwise are not subject to liability under those sections.

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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: November 13, 2012

AMERICAN MIDSTREAM PARTNERS, LP

By:	American Midstream GP, LLC
By:	/s/ Brian F. Bierbach
Name:	Brian F. Bierbach
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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EXHIBIT INDEX

Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	Second Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
3.3	Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.5 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.5	First Amendment to Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
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