American Midstream Partners, LP
Form 10-Q
November 14, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 30, 2011

or

o **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 (State or other jurisdiction of incorporation or organization)	**27-0855785** (I.R.S. Employer Identification No.)
1614 15th Street, Suite 300 **Denver, CO** (Address of principal executive offices)	**80202** (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. o Yes þ 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). þ Yes o 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 o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

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

There were 4,528,208 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of November 10, 2011. Our common units trade on the New York Stock Exchange under the ticker symbol AMID.

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Glossary of Terms

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

Bbl	Barrels
BBtu	Billion British thermal units
Btu	British thermal units, a measure of heating value
/d	Per day
gal	Gallons
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBbl	Million barrels
MMBtu	Million British thermal units

MMcf	Million cubic feet
NGL or NGLs	Natural gas liquid(s)

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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FINANCIAL INFORMATION
Item 1. Financial Statements

American Midstream Partners, LP and Subsidiaries
Unaudited Condensed Consolidated Balance Sheets
(In thousands except unit amounts)

	September 30, 2011	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 530	$ 63
Accounts receivable	1,192	656
Unbilled revenue	18,086	22,194
Risk management assets	906	
Other current assets	1,696	1,523
Total current assets	22,410	24,436
Property, plant and equipment, net	137,590	146,808
Risk management assets long term	247	
Other assets	3,170	1,985
Total assets	$ 163,417	$ 173,229
Liabilities and Partners Capital		
Current liabilities		
Accounts payable	$ 1,225	$ 980
Accrued gas purchases	15,309	18,706
Current portion of long-term debt		6,000
Other loans		615
Risk management liabilities	502	
Accrued expenses and other current liabilities	5,393	2,676
Total current liabilities	22,429	28,977
Risk management liabilities long term		
Other liabilities	8,352	8,078
Long-term debt	29,350	50,370
Total liabilities	60,131	87,425
Commitments and contingencies (see Note 10)		
Partners capital		
General partner interest (0.2 and 0.1 million units outstanding as of September 30, 2011 and December 31, 2010, respectively)	1,771	2,124
Limited partner interest (9.1 and 5.4 million units outstanding as of September 30, 2011 and December 31, 2010, respectively)	101,376	83,624
Accumulated other comprehensive income	139	56

Total partners capital		103,286		85,804
Total liabilities and partners capital	$	163,417	$	173,229

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenue	$ 57,005	$ 53,158	$ 190,374	$ 155,686
Realized gain (loss) on early termination of commodity derivatives			(2,998)	
Unrealized gain (loss) on commodity derivatives	953	(205)	(19)	(231)
Total revenue	57,958	52,953	187,357	155,455
Operating expenses:				
Purchases of natural gas, NGLs and condensate	47,359	44,516	157,725	128,323
Direct operating expenses	3,385	3,097	9,548	9,370
Selling, general and administrative expenses	2,497	1,803	7,649	5,061
Advisory services agreement termination fee (See Note 11)	2,500		2,500	
Equity compensation expense	331	464	2,989	1,255
Depreciation expense	5,261	5,014	15,468	14,962
Total operating expenses	61,333	54,894	195,879	158,971
Operating income (loss)	(3,375)	(1,941)	(8,522)	(3,516)
Other income (expenses):				
Interest expense	(1,378)	(1,419)	(3,923)	(4,151)
Gain on sale of assets, net	586		586	
Net income (loss)	$ (4,167)	$ (3,360)	$ (11,859)	$ (7,667)
General partner s interest in net income (loss)	(83)	(67)	(237)	(153)
Limited partners interest in net income (loss)	$ (4,084)	$ (3,293)	$ (11,622)	$ (7,514)
Limited partners net income (loss) per unit (See Note 13)	$ (0.53)	$ (0.66)	$ (1.85)	$ (1.51)
Weighted average number of units used in computation of limited partners net income (loss) per unit	7,774	5,001	6,296	4,982

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

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

	Limited Partner Common Units	Limited Partner Subordinated Units	Limited Partner Interest	General Partner Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
Balances at December 31, 2009	4,756		$ 91,148	97	$ 2,010	$ 46	$ 93,204
Net income (loss)			(7,514)		(153)		(7,667)
Unitholder contributions	238		4,900	5	100		5,000
Unitholder distributions			(8,359)		(171)		(8,530)
Unit based compensation					864		864
Adjustments to other post retirement plan assets and liabilities						69	69
Balances at September 30, 2010	4,994		$ 80,175	102	$ 2,650	$ 115	$ 82,940
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

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

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

	Nine Months Ended September 30,	
	2011	**2010**
Cash flows from operating activities		
Net income (loss)	$ (11,859)	$ (7,667)
Adjustments to reconcile change in net assets to net cash used in operating activities:		
Depreciation expense	15,468	14,962
Amortization of deferred financing costs	1,121	592
Mark-to-market on derivatives	19	254
Unit based compensation	1,234	864
(Gain) on disposal of assets	(586)	
Changes in operating assets and liabilities:		
Accounts receivable	(536)	956
Unbilled revenue	4,108	2,417
Risk management assets	(670)	(308)
Other current assets	(173)	1,406
Other assets	33	22
Accounts payable	(108)	(265)
Accrued gas purchases	(3,397)	(859)
Accrued expenses and other current liabilities	2,717	895
Other liabilities	(272)	1,294
Net cash provided (used) in operating activities	7,099	14,563
Cash flows from investing activities		
Additions to property, plant and equipment	(4,890)	(7,913)
Disposals of property, plant and equipment	125	
Net cash provided (used) in investing activities	(4,765)	(7,913)
Cash flows from financing activities		
Unit holder distributions	(41,061)	(8,530)
Proceeds upon issuance of common units to public, net of offering costs	69,085	
Unit holder contributions		5,000
Payments on other loan	(615)	(815)
Deferred debt issuance costs	(2,256)	
Borrowings on long-term debt	76,850	18,900
Payments on long-term debt	(103,870)	(22,330)
Net cash provided (used) in financing activities	(1,867)	(7,775)
Net increase (decrease) in cash and cash equivalents	467	(1,125)
Cash and cash equivalents		
Beginning of period	63	1,149

End of period	$	530	$	24
Supplemental cash flow information				
Interest payments	$	3,201	$	3,372
Supplemental non-cash information				
Accrual of property, plant and equipment	$	353	$	525

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 Unaudited Condensed Consolidated Financial Statements

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 interstate natural gas pipeline assets transport natural gas through Federal Energy Regulatory Commission (the FERC) regulated interstate natural gas pipelines in Louisiana, Mississippi, Alabama and Tennessee. Our interstate pipelines include:

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

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

Basis of Presentation

These unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include disclosures required by GAAP for annual periods. The unaudited condensed consolidated financial statements for the three months and nine months ended September 30, 2011 and 2010 include all adjustments and disclosures that we believe are necessary for a fair statement of the results for the interim periods.

Our financial results for the three months and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2011. These unaudited condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our final prospectus dated July 26, 2011 (the Prospectus) filed with the Securities and Exchange Commission pursuant to Rule 424 on July 27, 2011.

We have made a reclassification to amounts reported in prior period unaudited condensed consolidated financial statements to conform to our current period presentation. These reclassifications did not have an impact on net income for the periods previously reported.

2. Summary of Significant Accounting Policies

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

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

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record those fees separately in revenues. For the three months and nine months ended September 30, 2011 and 2010, respectively, the Partnership recognized the following revenues by category:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue				
Transportation firm	$ 2,077	$ 2,085	$ 7,572	$ 7,527
Transportation interruptible	888	773	2,671	2,341
Sales of natural gas, NGLs and condensate	53,833	50,221	179,545	145,594
Other	207	79	586	224
Realized gain (loss) on early termination of commodity derivatives			(2,998)	
Unrealized gain (loss) on commodity derivatives	953	(205)	(19)	(231)
Total revenue	$ 57,958	$ 52,953	$ 187,357	$ 155,455

Limited Partners Net Income (Loss) Per Unit

We compute limited partners net income (loss) per 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 of our limited partners net income (loss) per unit are made in accordance with the FASB Accounting Standards Codification (ASC) Topic 260, Earnings per Share . All per unit computations give effect to the retroactive application of the reverse unit split as described in Note 8, Partners Capital and Note 13, Net Income (Loss) Per Limited and General Partner Unit.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs*. The ASU amends previously issued authoritative guidance and is effective for interim and annual periods beginning after December 15, 2011. The amendments change requirements for measuring fair value and disclosing information about those measurements. Additionally, the ASU clarifies the FASB s intent regarding the application of existing fair value measurement requirements and changes certain principles or requirements for measuring fair value or disclosing information about its measurements. For many of the requirements, the FASB does not intend the amendments to change the application of the existing Fair Value Measurements guidance. This guidance will not have an impact on the Company s financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05 *Presentation of Comprehensive Income*. The ASU amends previously issued authoritative guidance and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. These amendments remove the option under current U.S. GAAP to present the components of other comprehensive income as part of the statements of changes in stockholder s equity. The adoption of this guidance will not have an impact on the Company s financial position or results of operations, but will require the Company to present the statements of comprehensive income separately from its statements of equity, as these statements are currently presented on a combined basis.

3. Concentration of Credit Risk and Trade Accounts Receivable

We maintain allowances for potentially uncollectible accounts receivable. For the nine-month period ended September 30, 2011 and 2010, no allowances on or write-offs of accounts receivable were recorded.

Enbridge Marketing (US) L.P., ConocoPhillips Corporation and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue in one or more of the periods presented, accounting for $10.5 million, $24.3 million and $10.1 million, respectively, of our consolidated revenue in the unaudited condensed consolidated statement of operations in the three months ended September 30, 2011 and $33.4 million, $78.6 million and $29.8 million, respectively, for the nine months ended September 30, 2011.

4. Derivatives

Commodity Derivatives

In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from cancelling our then-existing NGL swap contracts and entering into new NGL swap contracts with an existing counterparty that extend through the end of 2012. A $3.0 million realized loss resulting from the early termination of these swap contracts was recorded in the unaudited condensed consolidated statement of operations for the nine months ended September 30, 2011.

We may be required to post collateral with our counterparty in connection with our derivative positions. As of September 30, 2011, we had no posted collateral with our counterparty. Our counterparty is not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparty allowing us to offset our commodity derivative asset and liability positions.

As of September 30, 2011, the aggregate notional volume of our commodity derivatives was 14.6 million NGL gallons.

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Interest Rate Derivatives

We also utilize interest rate caps to protect against changes in interest rates on our floating rate debt. At September 30, 2011, we had $29.4 million outstanding under our new $100 million revolving credit facility with interest accruing at a rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates, we have entered into interest rate caps that mitigate the risk of increases in interest rates. As of September 30, 2011, we had interest rate caps with a notional amount of $22.0 million that effectively fix the base rate on that portion of our debt, with a fixed maximum rate of 4%.

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

As of September 30, 2011 and December 31, 2010, 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, 2011	December 31, 2010
	(in thousands)	
Risk management assets:		
Commodity derivatives	$ 1,153	$
Interest rate derivatives		
	$ 1,153	$
Risk management liabilities:		
Commodity derivatives	$ 502	$
Interest rate derivatives		
	$ 502	$

For the three and nine months ended September 30, 2011 and 2010 we recorded the following unrealized mark-to-market gains (losses):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Commodity derivatives	$ 953	$ (205)	$ (19)	$ (231)
Interest rate derivatives		(8)		(23)
	$ 953	$ (213)	$ (19)	$ (254)

Fair Value Measurements

Our interest rate caps and commodity derivatives discussed above were classified as Level 3 derivatives for all periods presented.

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 for the relevant settlement periods.

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands)			
Fair value asset (liability), beginning	$ (302)	$ 344	$	$ 77
Realized gain (loss) on early termination of commodity derivatives			(2,998)	
Unrealized gain (loss) on commodity derivatives	953	(205)	(19)	(231)
Unrealized gain (loss) on interest rate cap		(8)		(23)
Purchases			670	308
Settlements			2,998	
Fair value asset (liability), ending	$ 651	$ 131	$ 651	$ 131

Also included in revenue were ($0.4) million and ($1.3) million in realized gains (losses) for the three and nine months ended September 30, 2011, respectively, representing our monthly swap settlements. No such gains (losses) were recorded for the three and nine months ended September 30, 2010.

5. Property, Plant and Equipment, Net

Property, plant and equipment, net, as of September 30, 2011 and December 31, 2010 were as follows:

	Useful Life	September 30, 2011	December 31, 2010
		(in thousands)	
Land		$ 41	$ 41
Buildings and improvements	4 to 40	4,684	2,523
Processing and treating plants	8 to 40	10,978	11,954
Pipelines	5 to 40	146,905	143,805
Compressors	4 to 20	8,032	7,163
Equipment	8 to 20	1,653	1,711
Computer software	5	1,506	1,390
Total property, plant and equipment		173,799	168,587
Accumulated depreciation		(36,209)	(21,779)
Property, plant and equipment, net		$ 137,590	$ 146,808

Of the gross property, plant and equipment balances at September 30, 2011 and December 31, 2010, $24.0 million was related to AlaTenn and Midla, our FERC regulated interstate assets.

6. 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. Typically, we record an ARO at the time the assets are installed or acquired if a reasonable estimate of fair value can then be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for an ARO when assets are taken out of service or otherwise abandoned.

During the year ended December 31, 2010, we recognized $6.1 million of ARO which is 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 in our unaudited condensed consolidated statements of operations, of $0.4 million and $0.3 million for the three months ended September 30, 2011 and 2010, respectively, and $1.0 million and $0.9 million for the nine months ended September 30, 2011 and 2010, respectively, related to these AROs.

No assets were legally restricted for purposes of settling our ARO liabilities during the nine months ended September 30, 2011 and 2010. Following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for the three and nine months ended September 30, 2011 and 2010, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Balance at beginning of period	$ 7,921	$ 6,646	$ 7,249	$
Additions				6,084
Reductions	(486)		(486)	
Expenditures	(2)	(2)	(10)	(8)
Accretion expense	352	304	1,032	872
Balance at end of period	$ 7,785	$ 6,948	$ 7,785	$ 6,948

In August 2011, we sold an abandoned portion of pipe for which we had recorded an ARO. As a result of this sale, we are no longer responsible for the costs of abandonment on this pipe and have reduced our ARO during the three months ended September 30, 2011 by $0.5 million.

7. Long-Term Debt

On November 4, 2009, we entered into an $85 million secured credit facility (old credit facility) with a consortium of lending institutions. The old credit facility was composed of a $50 million term loan facility and a $35 million revolving credit facility.

On August 1, 2011, we terminated the old credit facility and entered into our $100 million revolving credit facility (new credit facility). This new credit facility also contains a $50 million accordion feature which could bring total the total facility commitment to $150 million.

The new credit facility provides for a maximum borrowing equal to the lesser of (i) $100 million or (ii) 4.50 times adjusted consolidated EBITDA. We may elect to have loans under the new 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, 2011 and 2010, the weighted average interest rate on borrowings under our old and new credit facilities were approximately 7.37% and 7.35%, respectively.

Our obligations under the new credit facility are secured by a first mortgage in favor of the lenders in our real property. The terms of the new credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, August 1, 2016.

The new 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

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customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the new 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 new credit facility as of September 30, 2011.

Our outstanding borrowings under the new credit facility at September 30, 2011 and the old credit facility at December 31, 2010, respectively, were:

	September 30, 2011	December 31, 2010
	(in thousands)	
Term loan facility	$	$ 45,000
Revolving loan facility	29,350	11,370
	29,350	56,370
Less: current portion		6,000
	$ 29,350	$ 50,370

At September 30, 2011 and December 31, 2010, respectively, letters of credit outstanding under the old and new credit facilities were $0.6 million.

In connection with our new credit facility, we incurred $2.3 million in debt issuance costs which are being amortized on a straight line basis until maturity of the new credit facility.

Fair Market Value of Financial Instruments

We use various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of our new and old credit facilities approximates fair value, because the interest rate on both facilities are variable.

8. Partners Capital

Our capital accounts are comprised of a 2% general partner interest and 98% limited partner interests. Our limited partners have limited rights of ownership as provided in 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 that may be made pursuant to the incentive distribution rights that are nonvoting limited partner interests held by our general partner.

On August 1, 2011, we closed the initial public offering (the IPO) of 3,750,000 of our common units at an offering price of $21 per unit. 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 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 Prospectus.

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 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 general partner s long term incentive plan (the 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 to us the common units contributed to it by AIM Midstream Holdings in exchange for 76,019 general partner units in order to maintain its 2.0% general partner interest in us.

The number of units outstanding were as follows:

	September 30, 2011	December 31, 2010	September 30, 2010
		(in thousands)	
Limited partner units	4,526	5,363	4,994
Limited partner subordinated units	4,526		
General partner units	185	109	102

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

Distributions

We made distributions of $7.4 million and $8.5 million for the nine months ended September 30, 2011 and 2010, 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 AIM Midstream Holdings, participants in our LTIP holding common units and our general partner as described in the Prospectus.

9. 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 an LTIP for its employees, 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 LTIP. The LTIP currently permits the grant of awards that include phantom units that typically vest ratably over four years and may also include distribution equivalent rights (DER s), covering an aggregate of 303,601 of our units. A DER entitles the grantee to a cash payment equal to the cash distribution made by the us with respect to a unit during the period such DER is outstanding. At September 30, 2011 and December 31, 2010, 34,514 and 53,928 units, respectively, were available for future grant under the LTIP giving retroactive treatment to the reverse unit split described in Note 8 Partners Capital .

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 has not historically settled these awards in cash. Although other types of awards are contemplated under the LTIP, the only currently outstanding awards are phantom units without DERs.

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Grants issued under the LTIP vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment.

During 2011, the fair value of the grants issued was calculated by the general partner based on several valuation models, including: a 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 EBITDA and DCF) and certain assumptions in the calculation of enterprise value.

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,	
	2011	2010	2011	2010
Outstanding at beginning of period	209,824	237,055	205,864	175,237
Granted			19,414	61,818
Vested			(15,454)	
Outstanding at end of period	209,824	237,055	209,824	237,055
Grant date fair value per share	$ 14.70 to $19.69	$ 14.70 to $16.15	$ 14.70 to $19.69	$ 14.70 to $16.15

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our units at each balance sheet date. Compensation costs related to these awards for the three months ended September 30, 2011 and 2010 was $0.3 million and $0.5 million, respectively, and for the nine months ended September 30, 2011 and 2010 was $3.0 million and $1.3 million, respectively, which is classified as equity compensation expense in the consolidated statement of operations and the noncash portion in partners capital on the consolidated balance sheet.

The total compensation cost related to unvested awards not yet recognized on September 30, 2011 and December 31, 2010 was $3.0 million and $3.8 million, respectively, and the weighted average period over which this cost is expected to be recognized is approximately 2 years.

10. 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 operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Commitments and contractual obligations

Future non-cancelable commitments related to certain contractual obligations as of September 30, 2011 are presented below:

	Payments Due by Period (in thousands)						
	Total	2011	2012	2013	2014	2015	Thereafter
Operating leases and service contract	$ 1,918	$ 144	$ 415	$ 361	$ 377	$ 367	$ 254
ARO	7,785						7,785

Total	$ 9,703	$ 144	$ 415	$ 361	$ 377	$ 367	$ 8,039

For the periods indicated, total expenses related to operating leases, asset retirement obligations, land site leases and right-of-way agreements were:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Operating leases	$ 177	$ 227	$ 578	$ 545
ARO	2	2	10	8
	$ 179	$ 229	$ 588	$ 553

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 MDEQ the SO_2 emissions from the Bazor Ridge plant for 2009 and 2010. Moreover, we recently discovered that SO_2 emission levels during 2009 may have exceeded the threshold that triggers the need for a Prevention of Significant Deterioration, or a PSD, permit under the federal Clean Air Act. No PSD permit has been issued for the Bazor Ridge plant. In addition, we recently 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 the EPA.

If the MDEQ or the EPA were to initiate enforcement proceedings with respect to these exceedances and violations, we could be subject to monetary sanctions and our Bazor Ridge plant could become subject to restrictions or limitations (including the possibility of installing additional emission controls) on its operations or be required to obtain a PSD permit or to amend its current Title V Air Permit. 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. Although enforcement proceedings are reasonably possible, we cannot estimate the financial impact on us from such enforcement proceedings until we have completed an investigation of these matters and met with the agencies to determine treatment, extent, and reportability any of exceedances and violations. As a result, we have not recorded a loss contingency as the criteria under ASC 450, Contingencies has not been met.

In addition, if emission levels for our Bazor Ridge plant were not properly reported by the prior owner or if a PSD permit was required 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. If one or both of the MDEQ and the EPA pursue enforcement actions or other sanctions against the prior owner, we may have an obligation under our purchase agreement with the prior owner to indemnify them for any losses (as defined in the purchase agreement) that may result. Because the existence and extent of any violations is unknown at this time, the financial impact of any amounts due regulatory agencies and/or the prior owner cannot be reasonably estimated at this time.

We are in communication with regulatory officials at both the MDEQ and the EPA regarding the Bazor Ridge plant reporting issue.

11. Related-Party Transactions

Employees of our general partner are assigned to work for us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our general partner to American Midstream, LLC which, in turn, charges the appropriate subsidiary. Our general partner does not record any profit or margin for the administrative and operational services charged to us. During the three months ended September 30, 2011 and 2010, administrative and operational services expenses of $2.0 million and $1.9 million, respectively, were charged to us by our general partner. During the nine months ended September 30, 2011 and 2010, administrative and operational services expenses of $7.4 million and $5.2 million, respectively, were charged to us by our general partner.

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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. For each of the three months ended September 30, 2011 and 2010, less than $0.1 million had been recorded to selling, general and administrative expenses under this agreement. For each of the nine months ended September 30, 2011 and 2010, $0.1 million had been recorded to selling, general and administrative expenses under this agreement.

On August 1, 2011 and in connection with our IPO, we terminated the advisory services agreement in exchange for a payment of $2.5 million.

12. 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 to producers of natural gas and oil, 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 and selling or delivering pipeline quality natural gas and NGLs to various markets and pipeline systems.

Transmission

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

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

The following tables set forth our segment information for the periods indicated:

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	Gathering and Processing	Transmission (in thousands)	Total
Three months ended September 30, 2011			
Revenue	$41,218	$15,787	$57,005
Segment gross margin (a),(b)	6,821	2,825	9,646
Realized gains (loss) on early termination of commodity derivatives			
Unrealized gains (loss) on commodity derivatives	953		953
Direct operating expenses			3,385
Selling, general and administrative expenses			2,497
Advisory services agreement termination fee			2,500
Equity compensation expense			331
Depreciation expense			5,261
Interest expense			1,378
Gain on sale of assets, net			586
Net income (loss)			(4,167)

	Gathering and Processing	Transmission (in thousands)	Total
Three months ended Sepetmber 30, 2010			
Revenue	$34,974	$18,184	$53,158
Segment gross margin (a)	5,720	2,717	8,437
Direct operating expenses			3,097
Selling, general and administrative expenses			1,803
Equity compensation expense			464
Depreciation expense			5,014
Interest expense			1,419
Net income (loss)			(3,360)

	Gathering and Processing	Transmission (in thousands)	Total
Nine months ended September 30, 2011			
Revenue	$138,487	$51,887	$190,374
Segment gross margin (a)(b)	22,988	9,661	32,649
Realized gains (loss) on early termination of commodity derivatives	(2,998)		(2,998)
Unrealized gains (loss) on commodity derivatives	(19)		(19)
Direct operating expenses			9,548
Selling, general and administrative expenses			7,649
Advisory services agreement termination fee			2,500
Equity compensation expense			2,989
Depreciation expense			15,468

Interest expense	3,923
Gain on sale of assets, net	586
Net income (loss)	(11,859)

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	Gathering and Processing	Transmission (in thousands)	Total
Nine months ended September 30, 2010			
Revenue	$119,663	$36,023	$155,686
Segment gross margin (a)	17,457	9,675	27,132
Direct operating expenses			9,370
Selling, general and administrative expenses			5,061
Equity compensation expense			1,255
Depreciation expense			14,962
Interest expense			4,151
Net income (loss)			(7,667)

(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 amounts for each of these segments. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Realized gains (losses) from the early termination of commodity derivatives and unrealized gains (losses) from derivative mark-to-market adjustments are included in total revenue and segment gross margin in our Gathering and Processing segment for the three and nine months ended September 30, 2010. 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 less than ($0.1) million, respectively, in unrealized gains (losses) on commodity derivatives were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized early termination costs on commodity derivatives. For the three and nine months ended September 30, 2011, zero dollars and ($3.0) million in realized (losses) on early termination of commodity derivatives 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 to monitor our performance and therefore is not disclosed.

For the purposes of our Gathering and Processing segment, for the three months ended September 30, 2011 and 2010, Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented significant customers, each representing more than 10% of our segment revenue in our Gathering and Processing segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented $7.1 million, $24.3 million and $4.5 million of segment revenue for the three months ended September 30, 2011 and $3.6 million, $19.1 million and $3.8 million for the three months ended September 30, 2010, respectively.

For the nine months ended September 30, 2011 and 2010, Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented significant customers, each representing more than 10% of our segment revenue in one or more of the periods presented in our Gathering and Processing segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented $22.0 million, $78.6 million and $12.2 million of segment revenue for the nine months ended September 30, 2011 and $40.6 million, $31.8 million and $13.8 million for the nine months ended September 30, 2010, respectively.

For the three months ended September 30, 2011 and 2010, Enbridge Marketing (US) L.P. and ExxonMobil Corporation represented significant customers, each representing more than 10% of our segment revenue in our Transmission segment. Our segment revenue derived from Enbridge Marketing (US) L.P.

and ExxonMobil Corporation represented $3.3 million and $10.1 million of segment revenue for the three months ended September 30, 2011 and $3.8 million and $10.4 million for the three months ended September 30, 2010, respectively.

For the nine months ended September 30, 2011 and 2010, Enbridge Marketing (US) L.P. and ExxonMobil Corporation represented significant customers, each representing more than 10% of our segment revenue in our Transmission segment. Our segment revenue derived from Enbridge Marketing (US) L.P. and ExxonMobil Corporation represented $11.4 million and $29.8 million of segment revenue for the nine months ended September 30, 2011 and $12.8 million and $14.0 million for the nine months ended September 30, 2010, respectively.

13. Net Income (Loss) per Limited and General Partner Unit

Net income (loss) is allocated to the general partner and the limited partners (common and subordinated unit holders) 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 unit is calculated by dividing limited partners interest in net income (loss) by the weighted average number of outstanding limited partner units during the period.

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

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

The two-class method does not impact our overall net income 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 have no dilutive securities, therefore basic and diluted net income per unit are the same.

We determined basic and diluted net income per general partner unit and limited partner unit as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2011	**2010**	**2011**	**2010**
Net loss attributable to general partner and limited partners	$(4,167)	$(3,360)	$(11,859)	$(7,667)
Weighted average general partner and limited partner units outstanding(a)(b)	7,932	5,098	6,421	5,079
Earnings per general partner and limited partner unit (basic and diluted)	$ (0.53)	$ (0.66)	$ (1.85)	$ (1.51)
Net loss attributable to limited partners	$(4,084)	$(3,293)	$(11,622)	$(7,514)
Weighted average limited partner units outstanding(a)(b)	7,774	5,001	6,296	4,982
Earnings per limited partner unit (basic and diluted)	$ (0.53)	$ (0.66)	$ (1.85)	$ (1.51)
Net loss attributable to general partner	$ (83)	$ (67)	$ (237)	$ (153)

Weighted average general partner units outstanding	158	97	125	97
Earnings per general partner unit (basic and diluted)	$ (0.53)	$ (0.69)	$ (1.90)	$ (1.58)

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a) Includes unvested phantom units with DERs, which are considered participating securities, of 237,055 as of September 30, 2010. There were no such unvested phantom units with DERs at September 30, 2011.

b) Gives effect to the reverse unit split as described in Note 8, Partners Equity .

14. Subsequent Event

On October 21, 2011, we announced a pro-rated distribution of $0.2690 per unit for the period from August 2, 2011 through September 30, 2011, payable on November 10, 2011 to unit holders of record on November 3, 2011.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report and the audited consolidated financial statements and notes thereto and management s discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 2010 included in our final prospectus dated July 26, 2011 (the Prospectus) that was filed with the Securities and Exchange Commission (the SEC) pursuant to Rule 424 on July 27, 2011. 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, pl 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 of this Quarterly Report, the Prospectus and the following:

- our ability to access 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 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 in this Quarterly Report and our Prospectus. 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 assets. We are engaged in the business of gathering, treating, processing and transporting natural gas through our ownership and operation of nine gathering systems, three processing facilities, two interstate pipelines and six intrastate pipelines. 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 percent-of-proceeds (POP) arrangements. We own three processing facilities that produced an average of approximately 52.0 Mgal/d and 51.7 Mgal/d of gross NGLs for the three months and nine months ended September 30, 2011, respectively. 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 23.7 Mgal/d and 28.3 Mgal/d of net equity NGL volumes for the three months and nine months ended September 30, 2011, 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, and 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.

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Significant Developments During the Three Months Ended September 30, 2011

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. In our IPO, we granted the underwriters a 30 day option to purchase up to 562,500 additional units to cover over-allotments, if any, on the same terms. This option expired unexercised on August 30, 2011.

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. These uses included the following:

- repayment in full of the outstanding balance under our $85 million credit facility of $58.6 million;

- termination, in exchange for a payment of $2.5 million, of the advisory services agreement between our subsidiary, American Midstream, LLC, and affiliates of American Infrastructure MLP Fund, L.P.;

- establishment of a cash reserve of $2.2 million related to our non-recurring deferred maintenance capital expenditures for the twelve months ending June 30, 2012; and

- the making of an aggregate distribution of $5.8 million, on a pro rata basis, to AIM Midstream Holdings, participants in our long-term incentive plan holding common units and the General Partner. The distribution to AIM Midstream Holdings and the General Partner was a reimbursement for certain capital expenditures incurred with respect to assets contributed to us.

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.

New $100 Million Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our $85 million credit facility (old 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 (new credit facility). The new credit facility also provides for a $50 million dollar accordion feature for accretive growth projects. If the accordion feature were to be fully exercised and approved by our lenders, the total commitment under the new facility would be $150 million.

In connection with our IPO, utilized a portion of the draws from our new 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 new 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.

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Subsequent Event

On October 21, 2011, we announced a pro-rated distribution of $0.2690 per unit for the period from August 2, 2011 through September 30, 2011, payable on November 10, 2011 to unit holders of record on November 3, 2011.

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 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.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include throughput volumes, gross margin and direct operating expenses on a segment basis, and adjusted EBITDA 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 and processing activities under fixed-margin and percent-of-proceeds arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to percent-of-proceeds arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

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

Effective January 1, 2011, we changed our gross margin and segment gross margin measure to exclude unrealized mark-to-market adjustments related to our commodity derivatives. For the three months and nine months ended September 30, 2011, $1.0 million and less than $(0.1) million, respectively, of unrealized gains (losses) were excluded from gross margin and the Gathering and Processing segment gross margin.

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 months and nine months ended September 30, 2011, zero dollars and $3.0 million, respectively, in realized losses were excluded from gross margin and the Gathering and Processing segment gross margin.

Direct Operating Expenses

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

Adjusted EBITDA

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

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

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

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 interest expense and maintenance capital expenditures. The GAAP measure most directly comparable to distributable cash flow is net cash flows from operating activities.

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. Because 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 12 to our unaudited condensed 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, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income	$ (4,167)	$ (3,360)	$ (11,859)	$ (7,667)
Add:				
Depreciation expense	5,261	5,014	15,468	14,962
Interest expense	1,378	1,419	3,923	4,151
Realized loss on early termination of commodity derivatives			2,998	
Unrealized (gain) loss on commodity derivatives	(953)	205	19	231
Non-cash equity compensation expense	331	307	1,234	864
Advisory services agreement termination fee	2,500		2,500	
Special distribution to holders of LTIP phantom units			1,624	

Transaction costs		21	281	228
Deduct:				
Gain on sale of assets, net	586		586	
Adjusted EBITDA	$ 3,764	$ 3,606	$ 15,602	$ 12,769

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands)			
Reconciliation of Distributable Cash to Net Cash Flows from Operating Activities:				
Net cash provided / (used) in operating activities	$ 1,331	$ 6,149	$ 7,099	$ 14,563
Add:				
Change in operating assets and liabilities	(713)	(3,776)	(1,702)	(5,558)
Interest expense	646	1,212	2,802	3,536
Advisory services agreement termination fee	2,500		2,500	
Realized (gain) loss on early termination of commodity derivatives			2,998	
Special distribution to holders of LTIP phantom units			1,624	
Transaction costs		21	281	228
Deduct:				
Cash interest expense (1)	646	1,212	2,802	3,536
Maintenance capital expenditures (2)	750	750	2,250	2,250
Distributable Cash Flow	$ 2,368	$ 1,644	$ 10,550	$ 6,983

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

(2) Amounts noted represent average estimated annual maintenance capital expenditures of $3.0 million which is what we expect to be required to maintain our assets over the long-term.

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 Prospectus.

We observe a number of trends around our assets. Favorable oil and NGL prices are driving ongoing development of shallow-water ultra-deep wells in the Gulf of Mexico, which we believe will benefit our Quivira system. We are also seeing increased drilling interest in the deeper plays served by our Bazor Ridge system. Major producers continue to drill and prove out the Tuscaloosa Marine Shale and Austin Chalk around our Midla and MLGT systems. During the third quarter, several wells have been either spudded or completed, and we have signed an agreement to bring new gas to Midla system. Finally, we have seen increased demand from the industrial and utility markets in northern Alabama, around our AlaTenn and Bamagas systems.

Our expectations are based on assumptions made by us 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 2011 was $2.1 million. Operating results for the three months ending September 30, 2011 showed significant increases over operating results for the 2010 comparable period. For the third quarter of 2011, gross margin increased 14% from that of the third quarter 2010. This positive performance was tempered, in part, by an unusual set of operational issues, both ours and third partys that reduced gathering and processing volumes which in turn impacted our financial performance.

For the Gloria and Lafitte systems, a work-over on the largest well supplying the Gloria system, a delay in connecting a well planned for the second quarter and compression challenges combined to reduce volumes into the TOCA processing plant. These issues have been largely addressed and volumes have returned to expected levels.

For the Quivira system, the Burns Point plant experienced compression challenges associated with unusually hot temperatures and the increased volumes our Quivira system brought to the plant, which reduced volumes and revenues on Quivira during the third quarter. We are working with Enterprise, the operator of the Burns Point plant, to proactively address this dynamic before next summer, which we believe is achievable. Quivira is again operating as expected.

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,	
	2011	2010	2011	2010
	(in thousands)			
Statement of Operations Data:				
Revenue	$ 57,005	$ 53,158	$ 190,374	$ 155,686
Realized gain (loss) on early termination of commodity derivatives			(2,998)	
Unrealized gain (loss) on commodity derivatives	953	(205)	(19)	(231)
Total revenue	57,958	52,953	187,357	155,455
Operating expenses				
Purchases of natural gas, NGLs and condensate	47,359	44,516	157,725	128,323
Direct operating expenses	3,385	3,097	9,548	9,370
Selling, general and administrative expenses	2,497	1,803	7,649	5,061
Advisory services agreement termination fee	2,500		2,500	
Equity compensation expense (1)	331	464	2,989	1,255
Depreciation expense	5,261	5,014	15,468	14,962
Total operating expenses	61,333	54,894	195,879	158,971
Operating income (loss)	(3,375)	(1,941)	(8,522)	(3,516)
Interest (expense)	(1,378)	(1,419)	(3,923)	(4,151)
Gain (loss) on sale of assets, net	586		586	
Net income (loss)	$ (4,167)	$ (3,360)	$ (11,859)	$ (7,667)
Other Financial Data:				
Gross margin (2)	$ 9,646	$ 8,437	$ 32,649	$ 27,132
Adjusted EBITDA (3)	$ 3,764	$ 3,606	$ 15,602	$ 12,769
Distributable cash flow (4)	$ 2,368	$ 1,644	$ 10,550	$ 6,983

(1) Represents cash and non-cash costs related to our LTIP. Of these amounts, $0.3 million and $0.5 million, for the three months ended September 30, 2011 and 2010, respectively and $1.2 million and $0.9 million for the nine months ended September 30, 2011 and 2010, respectively, were non-cash expenses.

(2) 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 12 to our unaudited consolidated financial statements included in Item 1. Financial Statements of this Quarterly Report and for a discussion of how we use gross margin to evaluate our operating performance, please read How We Evaluate Our Operations .

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

(4) 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, 2011 Compared to Three Months Ended September 30, 2010

Revenue. Our total revenue in the three months ended September 30, 2011 was $58.0 million compared to $53.0 million in the three months ended September 30, 2010. This increase of $5.0 million was primarily due to higher NGL sales volumes from owned processing plants and higher NGL prices and higher natural gas sales volumes in our gathering and processing segment. This increase was partially offset by lower natural gas sales volumes in our transmission segment and lower natural gas prices in our Gathering and Processing segment.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended September 30, 2011 were $47.4 million compared to $44.6 million in the three months ended September 30, 2010. This increase of $2.8 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes in our Gathering and Processing segment. This increase was partially offset by lower natural gas purchase volumes in our Transmission segment and lower natural gas prices in both segments.

Gross Margin. Gross margin in the three months ended September 30, 2011 was $9.6 million compared to $8.4 million in the three months ended September 30, 2010. This increase of $1.2 million was primarily due to higher throughput volumes, plant inlet volumes and NGL prices in our Gathering and Processing segment as well as the impact of a $(0.2) million unrealized (loss) on commodity derivatives recognized in 2010 in our Gathering and Processing segment.

Direct Operating Expenses. Direct operating expenses in the three months ended September 30, 2011 were $3.4 million compared to $3.1 million in the three months ended September 30, 2010. This increase of $0.3 million was primarily due to an increase in fuel lost and unaccounted for of $0.3 million.

Selling, General and Administrative Expenses. SG&A expenses in the three months ended September 30, 2011 were $2.5 million compared to $1.8 million in the three months ended September 30, 2010. This increase of $0.7 million was primarily due to a reduction of $0.3 million in capitalized overhead costs, increased payroll costs of $0.2 million and $0.1 million in increased contract service costs.

Advisory Services Agreement Termination Fee. In connection with our IPO in August 2011, we terminated the advisory services agreement with our sponsor in exchange for a payment of $2.5 million.

Equity Compensation Expense. Compensation expense related our LTIP in the three months ended September 30, 2011 was $0.3 million compared to $0.5 million in the three months ended September 30, 2010. This decrease of $0.2 million was primarily due to the elimination of DER payments in the second quarter of 2011 which was offset, in part, by the amortization associated with new LTIP grants in March 2011.

Depreciation Expense. Depreciation expense in the three months ended September 30, 2011 was $5.3 million compared to $5.0 million in the three months ended September 30, 2010. This increase of $0.3 million was due to depreciation associated with capital projects placed into service during the period.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Revenue. Our total revenue in the nine months ended September 30, 2011 was $187.4 million compared to $155.4 million in the nine months ended September 30, 2010. This increase of $32.0 million was primarily due to higher NGL sales volumes from owned processing plants, higher NGL prices and higher natural gas sales volumes in both of our Gathering and Processing and Transmission segments as well as the impact of a $0.2 million unrealized loss on commodity derivatives recognized in 2010 in our Gathering and Processing segment. This increase was partially offset by lower realized natural gas prices in the Gathering and Processing and Transmission segments.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the nine months ended September 30, 2011 were $157.7 million compared to $128.3 million in the nine months ended September 30, 2010. This increase of $29.4 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes associated with a fixed margin contract in our Transmission segment. This increase was partially offset by lower natural gas prices in both segments.

Gross Margin. Gross margin in the nine months ended September 30, 2011 was $32.6 million compared to $27.1 million in the nine months ended September 30, 2010. This increase of $5.5 million was primarily due to higher throughput volumes, plant inlet volumes and realized NGL prices in our Gathering and Processing segment as well as the impact of a $0.2 million unrealized loss on commodity derivatives recognized in 2010 in our Gathering and Processing segment.

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Direct Operating Expenses. Direct operating expenses in the nine months ended September 30, 2011 were $9.6 million compared to $9.4 million in the nine months ended September 30, 2010. This increase of $0.2 million was primarily due to an increase in fuel lost and unaccounted for of $0.3 million.

Selling, General and Administrative Expenses. SG&A expenses in the nine months ended September 30, 2011 were $7.6 million compared to $5.1 million in the nine months ended September 30, 2010. This increase of $2.5 million was primarily due to increased payroll and benefit costs of $1.5 million, a reduction in capitalized overhead costs of $0.2 million, increased consulting fees of $0.3 million and public company costs, such as legal and accounting fees, of $0.3 million.

Advisory Services Agreement Termination Fee. In connection with our IPO in August 2011, we terminated the advisory services agreement with our sponsor in exchange for a payment of $2.5 million.

Equity Compensation Expense. Compensation expense related to our LTIP in the nine months ended September 30, 2011 were $3.0 million compared to $1.3 million in the nine months ended September 30, 2010. This increase of $1.7 million was primarily due to buy-out costs associated with the elimination of the DER provision in existing LTIP agreements in June 2011 and the amortization of new LTIP s granted in March 2011. This increase was partially offset by The absence of DER payments after the buy-out in June 2011.

Depreciation Expense. Depreciation expense in the nine months ended September 30, 2011 was $15.5 million compared to $15.0 million in the nine months ended September 30, 2010. This increase of $0.5 million was due to depreciation associated with capital projects placed into service during the period.

Results of Operations Segment Results

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

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands, except operating data)			
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$ 41,218	$ 34,974	$ 138,487	$ 119,663
Realized gain (loss) on early termination of commodity derivatives			(2,998)	
Unrealized gain (loss) on commodity derivatives	953	(205)	(19)	(231)
Total revenue	42,171	34,769	135,470	119,432
Purchases of natural gas, NGLs and condensate	34,398	29,049	115,500	101,976
Direct operating expenses	1,845	2,036	5,478	5,902
Other financial data:				
Segment gross margin	$ 6,821	$ 5,720	$ 22,988	$ 17,457
Operating data:				
Average throughput (MMcf/d)	209.0	170.3	227.6	167.2
Average plant inlet volume (MMcf/d) (1)	15.2	8.6	14.9	8.9
Average gross NGL production (Mgal/d) (1)	52.0	31.9	51.7	29.9
Average realized prices:				
Natural gas ($/MMcf)	$ 4.35	$ 4.50	$ 4.26	$ 4.67
NGLs ($/gal)	$ 1.38	$ 0.95	$ 1.35	$ 1.04
Condensate ($/gal)	$ 2.31	$ 1.73	$ 2.36	$ 1.76
Transmission segment				
Financial data:				
Total revenue	$ 15,787	$ 18,184	$ 51,887	$ 36,023
Purchases of natural gas, NGLs and condensate	12,961	15,467	42,225	26,347
Direct operating expenses	1,540	1,061	4,070	3,468
Other financial data:				
Segment gross margin	$ 2,825	$ 2,717	$ 9,661	$ 9,675
Operating data:				
Average throughput (MMcf/d)	373.6	373.2	377.7	336.0
Average firm transportation capacity reservation (MMcf/d)	655.7	655.9	693.0	659.6
Average interruptible transportation throughput (MMcf/d)	68.2	62.5	72.5	63.6

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

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010

Gathering and Processing Segment

Revenue. Segment revenue in the three months ended September 30, 2011 was $42.2 million compared to $34.8 million in the three months ended September 30, 2010. This increase of $7.4 million was, in part, due to higher NGL sales volumes at our Bazor Ridge processing plant. Inlet volumes at the plant increased over the period due to the completion of the Winchester lateral in the fourth quarter 2010. In addition, revenues also increased due to higher

NGL prices associated with our owned processing plants and elective processing agreements and higher natural gas sales volumes on our Bazor Ridge and Gloria systems. This increase was partially offset by lower realized natural gas prices.

Total natural gas throughput volumes on our Gathering and Processing segment were 209.0 MMcf/d in the three months ended September 30, 2011 compared to 170.3 MMcf/d in the three months ended September 30, 2010. Natural gas inlet volumes at our owned processing plants were 15.2 MMcf/d in the three months ended September 30, 2011 compared to 8.6 MMcf/d in the three months ended September 30, 2010. Gross NGL production volumes from our owned processing plants were 52.0 Mgal/d in the three months ended September 30, 2011 compared to 31.9 Mgal/d in the three months ended September 30, 2010. Primary factors influencing these gains were:

the connection of additional Contango production on our Quivira system representing a 24% increase over the same period in 2010;

a 78% increase in throughput volume from that of 2010 at our Bazor Ridge processing plant due to the completion of the Winchester Lateral in the fourth quarter of 2010; and

an increase in volumes across our Gloria system of 22% over the 2010 comparable period due to the connection of an additional supply source in the fourth quarter of 2010.

The average realized price of natural gas in the three months ended September 30, 2011 was $4.35/Mcf, compared to $4.50 /Mcf in the three months ended September 30, 2010. The average realized price of NGLs in the three months ended September 30, 2011 was $1.38/gal, compared to $0.95/gal in the three months ended September 30, 2010. The average realized price of condensate in the three months ended September 30, 2011 was $2.31/gal, compared to $1.73/gal in the three months ended September 30, 2010.

We entered into a series of swap and put contracts in January 2011 and swap contracts again in June 2011. These commodity derivative transactions had a positive net effect of $1.0 million on our revenue related to unrealized gains for the three months ended September 30, 2011. In June 2010, we purchased put contracts that extended through June 2011. For the three months ended September 30, 2010 we recognized an unrealized valuation (loss) of ($0.2) million related to this contract. For a discussion of our commodity derivative positions, please read Quantitative and Qualitative Disclosures about Market Risk.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended September 30, 2011 were $34.4 million compared to $29.1 million for the three months ended September 30, 2010. This increase of $5.3 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes on our Bazor Ridge and Gloria systems. This increase was partially offset by lower natural gas purchase prices.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2011 was $6.8 million compared to $5.7 million for the three months ended September 30, 2010. This increase of $1.1 million was primarily due to higher throughput volumes on our Quivira system from the connection of additional production in the third quarter of 2010, increased plant inlet volumes at our Bazor Ridge plant due to the completion of the Winchester lateral in the fourth quarter 2010 and higher NGL prices on both our Bazor Ridge and Gloria systems. In addition, a $0.2 million unrealized loss on commodity derivatives was recognized in 2010. Gathering and Processing segment represented 70.7% of our total gross margin for the three months ended September 30, 2011, compared to 67.8% for the three months ended September 30, 2010.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2011 were $1.8 million compared to $2.0 million for the three months ended September 30, 2010. This decrease of $0.2 million was primarily due to a decrease in outside consulting services.

Transmission Segment

Revenue. Segment revenue for the three months ended September 30, 2011 was $15.8 million compared to $18.2 million for the three months ended September 30, 2010. Total natural gas throughput on our Transmission systems for the three months ended September 30, 2011 was 373.6 MMcf/d compared to 373.2 MMcf/d in the three months ended September 30, 2010. This decrease of $2.4 million in revenue was primarily due to lower natural gas sales volumes associated with a fixed margin contract on our MLGT system that we converted to an interruptible transportation agreement. Our commodity derivatives had no effect on segment revenue for the three months ended September 30, 2011 and 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended September 30, 2011 were $13.0 million compared to $15.5 million for the three months ended September 30, 2010. This decrease of $2.5 million was primarily due to lower natural gas purchase volumes associated with our fixed margin contract on our MLGT system.

Segment Gross Margin. Segment gross margin for the three months ended September 30, 2011 was $2.8 million compared to $2.7 million for the three months ended September 30, 2010. This increase of $0.1 million was primarily due to additional transportation fees. Segment gross margin for the Transmission segment represented

29.3% of our total gross margin for the three months ended September 30, 2011, compared to 32.2% for the three months ended September 30, 2010.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2011 were $1.6 million compared to $1.1 million for the three months ended September 30, 2010. This increase of $0.5 million was primarily due to increased line loss of $0.3 million and $0.1 million in outside services.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Gathering and Processing Segment

Revenue. Segment revenue in the nine months ended September 30, 2011 was $135.5 million compared to $119.4 million in the nine months ended September 30, 2010. This increase of $16.1 million was primarily due to higher NGL and condensate sales volumes at our Bazor Ridge processing plant. Inlet volumes at the plant increased due to the completion of the Winchester lateral in the fourth quarter 2010. In addition, revenues also increased due to higher realized NGL and condensate prices associated with our owned processing plants and elective processing agreements and higher natural gas sales volumes on our Bazor Ridge and Gloria systems. This increase was partially offset by lower realized natural gas prices. Set forth below is a comparison of the volumetric and pricing data for the nine months ended September 30, 2011 and 2010, as well as a summary of the effect of the commodity derivative transactions that we entered into in January 2011.

Total natural gas throughput volumes on our Gathering and Processing segment were 227.6 MMcf/d in the nine months ended September 30, 2011 compared to 167.2 MMcf/d in the nine months ended September 30, 2010. Natural gas inlet volumes at our owned processing plants were 14.9 MMcf/d in the nine months ended September 30, 2011 compared to 8.9 MMcf/d in the nine months ended September 30, 2010. Gross NGL production volumes from our owned processing plants were 51.7 Mgal/d in the nine months ended September 30, 2011 compared to 29.9 Mgal/d in the nine months ended September 30, 2010. Primary factors influencing these gains were:

- The Connection of additional Contango production on our Quivira system representing a 54% increase over the same period in 2010;

- A 61% increase in throughput volume from that of 2010 at our Bazor Ridge processing plant due to the the completion of the Winchester Lateral in the fourth quarter of 2010; and

- an increase in volumes across our Gloria system of 23% over the 2010 comparable period due to the connection of an additional supply source in the fourth quarter of 2010.

The average realized price of natural gas in the nine months ended September 30, 2011 was $4.26/Mcf, compared to $4.67/Mcf in the nine months ended September 30, 2010. The average realized price of NGLs in the nine months ended September 30, 2011 was $1.35/gal, compared to $1.04/gal in the nine months ended September 30, 2010. The average realized price of condensate in the nine months ended September 30, 2011 was $2.36/gal, compared to $1.76/gal in the nine months ended September 30, 2010.

We entered into a series of swap and put contracts in January 2011 and swap contracts again in June 2011. Less than $0.1 million in unrealized valuation losses related to these commodity derivative contracts was recognized for the nine months ended September 30, 2011. In June 2010, we purchased put contracts that extended through June 2011. For the nine months ended September 30, 2010 we recognized an unrealized valuation loss of $0.2 million related to this contract. For a discussion of our commodity derivative positions, please read Quantitative and Qualitative Disclosures about Market Risk.

In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from cancelling our then-existing swap contracts and entering into a new swap contract with an existing counterparty that extends through the end of 2012. A $3.0 million realized loss resulting from the early termination of these swap contracts was recorded in the nine months ended September 30, 2011.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the nine months ended September 30, 2011 were $115.5 million compared to $102.0 million for the nine months ended September 30, 2010. This increase of $13.5 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes on our Bazor Ridge and Gloria systems. This increase was partially offset by lower realized natural gas purchase prices.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2011 was $22.9 million compared to $17.5 million for the nine months ended September 30, 2010. This increase of $5.4 million was primarily due to higher throughput volumes on our Quivira system from the connection of additional production in the third quarter of 2010, increased plant inlet volumes at our Bazor Ridge plant due to the completion of the Winchester lateral in the fourth quarter 2010, commencement of operations at our Atmore plant at the end of the second quarter 2010 and higher realized NGL prices on both our Bazor Ridge and Gloria systems. In addition, a $0.2 million unrealized loss on commodity derivatives was recognized in 2010. Segment gross margin for the Gathering and Processing segment represented 70.4% of our total gross margin for the three months ended September 30, 2011, compared to 64.3% for the three months ended September 30, 2010.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2011 were $5.5 million compared to $5.9 million for the nine months ended September 30, 2010. This decrease of $0.4 million was primarily the result of a decrease in chemical and supplies of $0.1 million and a $0.1 million decrease associated the cancellation of compressor lease agreement.

Transmission Segment

Revenue. Segment revenue for the nine months ended September 30, 2011 was $51.9 million compared to $36.0 million for the nine months ended September 30, 2010. Total natural gas throughput on our Transmission systems for the nine months ended September 30, 2011 was 377.7 MMcf/d compared to 336.0 MMcf/d in the nine months ended September 30, 2010. This increase of $15.9 million in revenue was primarily due to a new fixed-margin contract under which we purchase and simultaneously sell the natural gas that we transport, as opposed to typical contracts in this segment in which we receive a fixed fee for transporting natural gas. Our commodity derivatives had no effect on segment revenue for the nine months ended September 30, 2011and 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the nine months ended September 30, 2011 were $42.2 million compared to $26.3 million for the nine months ended September 30, 2010. This increase of $15.9 million was primarily due to the new fixed-margin contract.

Segment Gross Margin. Segment gross margin for the nine months ended September 30, 2011 was $9.7 million compared to $9.6 million for the nine months ended September 30, 2010. Segment gross margin for the Transmission segment represented 29.6% of our gross margin for the three months ended September 30, 2011, compared to 35.7% for the three months ended September 30, 2010.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2011 were $4.1 million compared to $3.5 million for the nine months ended September 30, 2010, or an increase of $0.6 million. This increase was primarily a result of increased line losses of $0.3 million and increased outside consulting services of $0.2 million.

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, 2011 were our cash on hand and availability under our new credit facility as discussed below. As of September 30, 2011, our available liquidity was $71.2 million, comprised of cash on hand of less than $0.5 million and $70.7 million available under our new credit facility. As of November 10, 2011, our available liquidity was $69.2 million.

In the near term, we expect our sources of liquidity to include cash generated from operations, borrowings under our new credit facility and issuances of debt and equity securities. We believe that the cash generated from these sources will be sufficient to allow us to distribute the minimum quarterly distribution on all of our outstanding common and subordinated units, the corresponding distribution on our 2.0% general partner interest and meet our requirements for working capital and capital expenditures over the next 12 months.

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Working Capital

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

Our working capital was zero dollars at September 30, 2011.

Cash Flows

The following table reflects cash flows for the applicable periods:

	Nine Months Ended September 30,	
	2011	**2010**
Net cash provided by (used in):		
Operating activities	$ 7,099	$ 14,563
Investing activities	(4,765)	(7,913)
Financing activities	(1,867)	(7,775)

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Operating Activities. Net cash provided by (used in) operating activities was $7.1 million for the nine months ended September 30, 2011 compared to $14.6 million for the nine months ended September 30, 2010. The change in cash provided by (used in) operating activities was primarily a result of the combined effects of a net loss, net of non-cash changes, in addition to net positive changes in operating assets and liabilities. In addition, $3.0 million was used to terminate our NGL swaps with two counterparties, purchase an NGL put for $0.7 million, $1.5 million was used to pay holders of phantom units under our LTIP in consideration for the elimination of the DER provision in existing LTIP agreements and $2.5 million was used to buy-out the management agreement with AIM.

Investing Activities. Net cash provided by (used in) investing activities was ($4.8) million for the nine months ended September 30, 2011 compared to ($7.9) million for the nine months ended September 30, 2010. Cash provided by (used in) investing activities for the nine months ended September 30, 2011 was primarily a result of a meter relocation costing $2.1 million on our MLGT system, $1.2 million for pipeline relocation work on our Gloria and Chalmette systems associated with levee improvements and $0.2 million for a Gloria compressor overhaul.

Financing Activities. Net cash provided by (used in) financing activities was ($1.9) million for the nine months ended September 30, 2011 compared to ($7.8) million for the nine months ended September 30, 2010. The change in cash provided by (used in) financing activities was primarily a result of $69.1 million in net proceeds from our IPO, a decrease in other unit holder contributions of ($5.0) million, the ($58.6) million pay down of our $85 million credit facility, an initial draw of $30.0 million from our new $100 million Credit Facility, debt issuance costs of ($2.3) million, a $5.0 million decrease in payments of long-term debt and an increase of ($32.6) million in distributions made to our unit holders.

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 or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) 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. We have budgeted $4.5 million in capital expenditures for the year ending December 31, 2011, of which $0.5 million represents expansion capital expenditures and $4.0 million represents maintenance capital expenditures.

For the three months and nine months ended September 30, 2011, our capital expenditures totaled $2.5 million and $4.9 million, respectively. For the nine month period, capital expenditures included maintenance capital expenditures of $1.3 million, reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a 3rd party) of $3.1 million and expansion capital project expenditures of $0.5 million. Although we classified our capital expenditures as maintenance, reimbursable and expansion capital expenditures, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our partnership agreement.

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 by borrowings under our new credit facility and the issuance of debt and equity securities.

Impact of Bazor Ridge Emissions Matter

With respect to our Bazor Ridge processing plant, we recently determined that (i) emissions during 2009 and 2010 exceeded the sulfur dioxide, or SO2, emission limits under our Title V Air Permit issued pursuant to the federal Clean Air Act, (ii) our emission levels may have required a Prevention of Significant Deterioration, or PSD, permit in 2009 under the federal Clean Air Act, and (iii) our SO2 emission levels required reporting under the federal Emergency Planning and Community Right-to-Know Act in 2009 and 2010 that was not made. Please read Business Environmental Matters Air Emissions in our Prospectus for more information about these matters.

As a result of these exceedances, we could be subject to monetary sanctions and our Bazor Ridge plant could become subject to restrictions or limitations (including the possibility of installing additional emission controls) on its operations or be required to obtain a PSD permit or to amend its current Title V Air Permit, the consequences of which (either individually or in the aggregate) could be material.

While we cannot currently estimate the amount or timing of any sanctions we might be required to pay, permits we might be required to obtain, or operational restrictions, limitations or capital expenditures that we might be required to make, we expect to use proceeds from additional borrowings under our new credit facility to pay any such sanctions or fund any such operational restrictions or limitations or capital expenditures.

We are in communication with regulatory officials at both the MDEQ and the EPA regarding the Bazor Ridge plant reporting issue.

Distributions

We intend to pay a quarterly distribution at an initial rate of $0.4125 per unit, which equates to an aggregate distribution of $3.8 million per quarter, or $15.2 million on an annualized basis, based on the number of common and subordinated units outstanding at September 30, 2011, as well as our 2.0% general partner interest. We do not have a legal obligation to make distributions except as provided in our partnership agreement.

In November 2011, we paid a pro-rated distribution for the period from August 2, 2011 through September 30, 2011 of $0.2690 per unit, or $2.5 million.

Contractual Obligations

As of September 30, 2011, except for changes in the ordinary course of our business, our contractual obligations have not changed materially from those reported in our Prospectus.

Critical Accounting Policies

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

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs.* The ASU amends previously issued authoritative guidance and is effective for interim and annual periods beginning after December 15, 2011. The amendments change requirements for measuring fair value and disclosing information about those measurements. Additionally, the ASU clarifies the FASB s intent regarding the application of existing fair value measurement requirements and changes certain principles or requirements for measuring fair value or disclosing information about its measurements. For many of the requirements, the FASB does not intend the amendments to change the application of the existing Fair Value Measurements guidance. This guidance will not have an impact on the Company s financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05 *Presentation of Comprehensive Income.* The ASU amends previously issued authoritative guidance and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. These amendments remove the option under current U.S. GAAP to present the components of other comprehensive income as part of the statements of changes in stockholder s equity. The adoption of this guidance will not have an impact on the Company s financial position or results of operations, but will require the Company to present the statements of comprehensive income separately from its statements of equity, as these statements are currently presented on a combined basis.

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 Prospectus. There have been no material changes to that information other than as discussed below. Also, see Note 4 to the unaudited condensed consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

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

As of September 30, 2011, we had hedged approximately 90% of our expected exposure to NGL prices in 2011, and approximately 79% in 2012.

The table below sets forth certain information regarding our NGL fixed swaps as of September 30, 2011:

Commodity	Period	Notional Volumes (gal/d)	Weighted Average Price ($/gal) We Receive	We Pay	Fair Market Value September 30, 2011
Ethane	July 2011 - Dec 2012	7,300	$ 0.57	OPIS avg	(284,134)
Propane	July 2011 - Dec 2012	7,050	$ 1.40	OPIS avg	105,761
Iso-Butane	July 2011 - Dec 2012	2,510	$ 1.81	OPIS avg	(27,848)
Normal Butane	July 2011 - Dec 2012	3,000	$ 1.74	OPIS avg	37,625
Natural Gasoline	July 2011 - Dec 2012	5,500	$ 2.31	OPIS avg	522,365
Total		25,360	$ 1.44		353,769

In January 2011, we entered into a put arrangement under which we receive a fixed floor price of $1.29 per gallon on a 9,800 gal/d of negotiated NGL basket, which includes ethane, propane, iso-butane, normal butane, natural gasoline and WTI crude oil. The relative weightings of the price of each component of the basket are calculated via an arithmetic formula.

The table below sets forth certain information regarding our NGL put as of September 30, 2011:

Commodity	Period	Notional Volumes (gal/d)	Floor Strike Price ($/gal)	Fair Market Value September 30, 2011
NGL basket	Feb 2011 to July 2012	9,800	$ 1.29	297,300

Interest Rate Risk

During the nine months ended September 30, 2011, we had exposure to changes in interest rates on our indebtedness associated with our new credit facility. Though we currently have interest rate cap contracts with a notional amount at November 10, 2011 of $20.5 million which limit our interest rate exposure to 4% through December 2, 2011, we anticipate that we will enter into new 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 to counter possible inflation. 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 $0.4 million for the nine months ended September 30, 2011.

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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 Chief Executive Officer (our principal executive officer) and our general partner s Vice President of Finance (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, 2011. This evaluation was performed by our management, with the participation of our general partner s Chief Executive Officer and Vice President of Finance. Based on this evaluation, our general partner s Chief Executive Officer and Vice President of Finance concluded that these controls and procedures are effective to ensure that the Partnership is able to collect, process and disclose the information it is required to disclose in the reports it files with the SEC within the required time periods, and during the quarterly period ended September 30, 2011 there have not been any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) identified in connection with this evaluation that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our general partner s Chief Executive Officer and Vice President of Finance 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 Chief Executive Officer and 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 I. 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 Prospectus 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 Prospectus. There have been no material changes to the risk factors previously disclosed in the Prospectus.

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

Sales of Unregistered Securities

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.

Use of Proceeds

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. In our IPO, we granted the underwriters a 30 day option to purchase up to 562,500 additional units to cover over-allotments, if any, on the same terms. This option expired unexercised on August 30, 2011.

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 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. These uses included the following:

- repayment in full of the outstanding balance under our $85 million credit facility of $58.6 million;
- termination, in exchange for a payment of $2.5 million, of the advisory services agreement between our subsidiary, American Midstream, LLC, and affiliates of American Infrastructure MLP Fund, L.P.;
- establishment of a cash reserve of $2.2 million related to our non-recurring deferred maintenance capital expenditures for the twelve months ending June 30, 2012; and
- the making of an aggregate distribution of $5.8 million, on a pro rata basis, to participants in our long-term incentive plan holding common units, AIM Midstream Holdings and the General

Partner. The distribution to AIM Midstream Holdings and the General Partner was a reimbursement for certain capital expenditures incurred with respect to assets contributed to us.

As described in the Prospectus, immediately following the repayment of the outstanding balance under our $85 million credit facility with the net proceeds of the IPO, we terminated our $85 million credit facility, entered into our new credit facility and borrowed $30.0 million. We used the proceeds from those borrowings to (i) make an aggregate distribution of $27.9 million, on a pro rata basis, to AIM Midstream Holdings, participants in our long-term incentive plan holding common units and the General Partner and (ii) pay fees and expenses of approximately $2.3 million relating to our new credit facility. The distribution made to AIM Midstream Holdings and the General Partner was a reimbursement for certain capital expenditures incurred with respect to assets contributed to us.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. (Removed and Reserved).

Item 5. Other Information.

Not applicable.

Item 6. Exhibits

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).
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, 2011 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Sandra M. Flower, Vice President of Finance of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the September 30, 2011 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, 2011 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2*	Certification of Sandra M. Flower, Vice President of Finance of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the September 30, 2011 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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SIGNATURES

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

Date: November 14, 2011

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/ Sandra M. Flower
Name: Sandra M. Flower
Title: Vice President of Finance
(principal financial officer)

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