American Midstream Partners, LP
Form 10-Q
September 09, 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 June 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 4,526,066 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of September 9, 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)

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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)

	June 30, 2011	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 62	$ 63
Accounts receivable	1,416	656
Unbilled revenue	21,347	22,194
Risk management assets	234	
Other current assets	1,941	1,523
Total current assets	25,000	24,436
Property, plant and equipment, net	140,136	146,808
Risk management assets long term	158	
Other assets	1,577	1,985
Total assets	$ 166,871	$ 173,229
Liabilities and Partners Capital		
Current liabilities		
Accounts payable	$ 1,187	$ 980
Accrued gas purchases	19,468	18,706
Current portion of long-term debt	8,000	6,000
Other loans	233	615
Risk management liabilities	678	
Accrued expenses and other current liabilities	4,290	2,676
Total current liabilities	33,856	28,977
Risk management liabilities long term	16	
Other liabilities	8,620	8,078
Long-term debt	52,700	50,370
Total liabilities	95,192	87,425
Commitments and contingencies (see Note 10)		
Partners capital		
General partner interest (0.1 million units outstanding as of June 30, 2011 and December 31, 2010)	2,193	2,124
Limited partner interest (5.4 million common units outstanding as of June 30, 2011 and December 31, 2010)	69,430	83,624
Accumulated other comprehensive income	56	56

Total partners capital	71,679	85,804
Total liabilities and partners capital	$ 166,871	$ 173,229

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Revenue	$ 66,030	$ 47,790	$ 133,369	$ 102,502
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)	
Unrealized gain (loss) on commodity derivatives	2,602		(972)	
Total revenue	65,634	47,790	129,399	102,502
Operating expenses:				
Purchases of natural gas, NGLs and condensate	55,413	38,843	110,366	83,807
Direct operating expenses	3,105	3,346	6,163	6,273
Selling, general and administrative expenses	2,663	1,560	5,152	3,258
Equity compensation expense	2,184	537	2,658	791
Depreciation expense	5,170	4,982	10,207	9,948
Total operating expenses	68,535	49,268	134,546	104,077
Operating income (loss)	(2,901)	(1,478)	(5,147)	(1,575)
Other expenses (income):				
Interest expense	1,281	1,375	2,545	2,732
Net income (loss)	$ (4,182)	$ (2,853)	$ (7,692)	$ (4,307)
General partner s interest in net income (loss)	(84)	(57)	(154)	(86)
Limited partners interest in net income (loss)	$ (4,098)	$ (2,796)	$ (7,538)	$ (4,221)
Limited partners net income (loss) per common unit (See Note 13)	$ (0.74)	$ (0.56)	$ (1.36)	$ (0.85)
Weighted average number of common units used in computation of limited partners net income (loss) per common unit	5,525	4,993	5,546	4,973

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 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)		(4,221)		(86)		(4,307)
Unitholder distributions		(5,174)		(106)		(5,280)
Unit based compensation				557		557
Adjustments to other post retirement plan assets and liabilities					36	36
Balances at June 30, 2010	4,756	$ 81,753	97	$ 2,375	$ 82	$ 84,210
Balances at December 31, 2010	5,363	$ 83,624	109	$ 2,124	$ 56	$ 85,804
Net income (loss)		(7,538)		(154)		(7,692)
Unitholder distributions		(7,192)		(146)		(7,338)
LTIP vesting	15	318		(318)		
Unit based compensation		218		687		905
Adjustments to other post retirement plan assets and liabilities						
Balances at June 30, 2011	5,378	$ 69,430	109	$ 2,193	$ 56	$ 71,679

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)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash flows from operating activities		
Net income (loss)	$ (7,692)	$ (4,307)
Adjustments to reconcile change in net assets to net cash used in operating activities:		
Depreciation expense	10,207	9,948
Amortization of deferred financing costs	389	393
Mark to market on derivatives	972	66
Unit based compensation	905	557
Changes in operating assets and liabilities:		
Accounts receivable	(760)	(499)
Unbilled revenue	847	(1,618)
Risk management assets	(670)	(308)
Other current assets	(418)	1,148
Other assets	19	41
Accounts payable	(267)	(625)
Accrued gas purchase	762	2,868
Accrued expenses and other current liabilities	1,614	694
Other liabilities	(138)	56
Net Cash provided (used) in operating activities	5,770	8,414
Cash flows from investing activities		
Additions to property, plant and equipment	(2,382)	(2,371)
Net Cash provided (used) in investing activities	(2,382)	(2,371)
Cash flows from financing activities		
Unit holder distributions	(7,338)	(5,280)
Payments on other loan	(381)	(538)
Borrowings on long-term debt	40,400	7,300
Payments on long-term debt	(36,070)	(7,800)
Net Cash provided (used) in financing activities	(3,389)	(6,318)
Net increase (decrease) in cash and cash equivalents	(1)	(275)
Cash and cash equivalents		
Beginning of period	63	1,149
End of period	$ 62	$ 874
Supplemental cash flow information		
Interest payments	$ 2,327	$ 2,229

Supplemental non-cash information				
Accrued property, plant and equipment	$	474	$	407

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

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 (date of inception) 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.

On August 1, 2011, we closed our initial public offering (IPO) of 3,750,000 common units at an offering price of $21 per unit. After deducting underwriting discounts and commissions of approximately $4.9 million paid to the underwriters, estimated offering expenses of approximately $4.1 million and a structuring fee of approximately $0.6 million, the net proceeds from our initial public offering were approximately $69.1 million. We used all of the net offering proceeds from our initial public offering for the uses described 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.

Immediately following the repayment of the outstanding balance under our $85 million credit facility with net proceeds of the IPO we terminated our $85 million credit facility and entered into a new $100 million revolving credit facility.

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 more than 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 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 consolidated financial statements for the three months and six months ended June 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 six months ended June 30, 2011 are not necessarily indicative of the results that may be expected for the full years ending December 31, 2011. These unaudited consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our prospectus.

We have made reclassifications to amounts reported in prior period consolidated financial statements to conform to our current period presentation. We made a reclassification $0.2 million from selling, general and administrative expenses to direct operating expenses in our consolidated statement of operations for the three months ended March 31, 2010. We made a reclassification of ($0.1) million from revenue to unrealized gain (loss) on commodity derivatives in our consolidated statements of income for the three month periods ended March 31, 2011. Neither of these reclassifications had an impact on net income for the periods previously reported.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenue				
Transportation firm	$ 2,177	$ 2,051	$ 5,495	$ 5,362
Transportation interruptible	818	837	1,783	1,568
Sales of natural gas, NGL s and condensate	62,781	44,767	125,677	95,428
Other	254	135	414	144
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)	
Unrealized gain (loss) on commodity derivatives	2,602		(972)	
Total revenue	$ 65,634	$ 47,790	$ 129,399	$ 102,502

Limited Partners Net Income (loss) Per Common Unit

We compute limited partners net income (loss) per common unit by dividing our limited partners interest in net income (loss) by the weighted average number of common units outstanding during the period. The overall computation, presentation and disclosure All per unit computation give effect to the retroactive application of the reverse unit split as described in Note 14, Subsequent Events , requirements for our limited partners net income (loss) per common unit are made in accordance with the Earnings per Share Topic of the Codification.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, requires additional disclosures with regard to fair value measurements categorized within Level 3 of the fair value hierarchy. Early adoption is not permitted.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, stipulates the financial statement presentation requirements for other comprehensive income.

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3. Concentration of Credit Risk and Trade Accounts Receivable

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

Enbridge Marketing (US) L.P., ConocoPhillips Corporation and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $10.9 million, $25.7 million and $10.1 million, respectively, of our consolidated revenue in the consolidated statement of operations in the three months ended June 30, 2011 and $23.0 million, $54.2 million and $19.7 million, respectively, for the six months ended June 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 swap contracts and entering into new swap contracts 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 three and six months ended June 30, 2011.

The Partnership may be required to post collateral with its counterparty in connection with its derivative positions. As of June 30, 2011, the Partnership had no posted collateral with this counterparty. The counterparty is not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with the Partnership s counterparty allowing the Partnership to offset its commodity derivative asset and liability positions.

As of June 30, 2011, the aggregate notional volumes of our commodity derivates was 17.8 million gallons.

Interest Rate Derivatives

The Partnership also utilizes interest rate caps to protect against changes in interest rates on its floating rate debt.

At June 30, 2011, the Partnership had $60.7 million outstanding under its 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, the Partnership has entered into interest rate caps that mitigate the risk of increases in interest rates. As of June 30, 2011, we had interest rate caps with a notional amount of $23.5 million that effectively fix the base rate on that portion of our debt, with a fixed maximum rate of 4%.

For accounting purposes, no derivative instruments were designated as hedging instruments and were instead accounted for under the mark-to-market method of accounting, with any changes in the 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

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financial instruments can cause noncash earnings volatility due to changes in the underlying commodity prices indices or interest rates.

As of June 30, 2011 and December 31, 2010, the fair value associated with the Partnership s derivative instruments were recorded in our financial statements, under the caption Risk management assets and Risk management liabilities, as follows:

	June 30, 2011	December 31, 2010
	(in thousands)	
Risk management assets:		
Commodity derivatives	$ 392	$
Interest rate derivatives		
	$ 392	$
Risk management liabilities:		
Commodity derivatives	$ 694	$
Interest rate derivatives		
	$ 694	$

We recorded the following unrealized mark-to-market gains (losses):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Commodity derivatives	$ 2,602	$	$ (972)	$
Interest rate derivatives		(7)		(15)
	$ 2,602	$ (7)	$ (972)	$ (15)

Fair Value Measurements

The Partnership s 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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands)			
Fair value asset (liability), beginning	$ (2,904)	$ 57	$	$ 77
Total realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)	(20)
Total unrealized gain (loss) on commodity derivatives	2,602		(972)	
Purchases		308	670	308
Settlements	2,998	(21)	2,998	(21)
Fair value asset (liability), ending	$ (302)	$ 344	$ (302)	$ 344

Also included in revenue were ($0.6) million and ($0.9) million in realized gains (losses) for the three and six months ended June 30, 2011, respectively, representing our monthly swap settlements. No such losses were recorded for the three and six months ended June 30, 2010.

5. Property, Plant and Equipment, Net

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

	Useful Life	June 30, 2011	December 31, 2010
		(in thousands)	
Land		$ 41	$ 41
Buildings and improvements	4 to 40	2,527	2,523
Processing and treating plants	8 to 40	11,960	11,954
Pipelines	5 to 40	146,078	143,805
Compressors	4 to 20	7,407	7,163
Equipment	8 to 20	1,966	1,711
Computer software	5	1,463	1,390
Total property, plant and equipment		171,442	168,587
Accumulated depreciation		(31,306)	(21,779)
Property, plant and equipment, net		$ 140,136	$ 146,808

Of the gross property, plant and equipment balances at June 30, 2011 and December 31, 2010, $24.3 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 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 AROs included in other liabilities for specific assets that we intend to retire for operational purposes. We recorded accretion expense, which is included in depreciation expense, of $0.3 million and $0.3 million in our consolidated statements of operations for the three months ended June 30, 2011 and 2010, respectively, and $0.7 million and $0.6 million in our consolidated statements of operations for the six months ended June 30, 2011 and 2010, respectively, related to these AROs.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Balance at beginning of period	$ 7,574	$ 6,361	$ 7,249	$
Additions				6,084
Expenditures		(5)	(8)	(5)
Accretion expense	347	290	680	567
Balance at end of period	$ 7,921	$ 6,646	$ 7,921	$ 6,646

7. Long-Term Debt

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

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

	June 30, 2011	December 31, 2010
	(in thousands)	
Term loan facility	$ 42,000	$ 45,000
Revolving loan facility	18,700	11,370
	60,700	56,370
Less: current portion	8,000	6,000
	$ 52,700	$ 50,370

At June 30, 2011 and December 31, 2010, letters of credit outstanding under the credit facility were $0.6 million.

The credit facility provides for a maximum borrowing equal to the lesser of (i) $85 million less the required amortization of term loan payments and (ii) 3.50 times adjusted consolidated EBITDA. We may elect to have loans under the credit facility bear interest either (i) at a Eurodollar-based rate with a minimum of 2.0% plus a margin ranging from 3.25% to 4.0% depending on our total leverage ratio then in effect, or (ii) at a base rate (the greater of (i) the daily adjusting LIBOR rate and (ii) a Prime-based rate which is equal to the greater of (A) the Prime Rate and (B) an interest rate per annum equal to the Federal Funds Effective Rate in effect that day, plus one percent) plus a margin ranging from 2.25% to 3.00% depending on the total leverage ratio then in effect. We also pay a facility fee of 1.0% per annum. In December 2009, we entered into an interest rate cap with participating lenders with a $23.5 million notional amount at June 30, 2011 that effectively caps our Eurodollar-based rate exposure on that portion of our debt at a maximum of 4.0%. For the six months ended June, 2011 and 2010, the weighted average interest rate on borrowings under our credit facility was approximately7.70% and 7.41%, respectively.

Our obligations under the credit facility are secured by a first mortgage in favor of the lenders in our real property. The terms of the credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest

will be due and payable in full on the maturity date, November 3, 2012. The term loan facility also provides for quarterly principal installment payments as described below:

Year	Amount (in thousands)
2011	$ 3,000
2012	39,000
	$ 42,000

The credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are (i) a total leverage ratio test (not to exceed 3.50 times) and a minimum interest coverage ratio test (not less than 2.50 times). We were in compliance with all of the covenants under our credit facility as of June 30, 2011.

As described in Note 14, Subsequent Events , on August 1, 2011 and in connection with the IPO, we paid off the amounts outstanding under our $85 million credit facility and entered into a $100 million revolving credit facility with Bank of America, and other financial institutions party thereto. This new credit facility matures August 1, 2016.

Fair Market Value of Financial Instruments

The Partnership used 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 the Partnership s credit facility approximates fair value, because the interest rate on the facility is 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 for under our partnership agreement and, as discussed below, the right to participate in our distributions. Our general partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the incentive distribution rights that are nonvoting limited partner interests held by our general partner.

The number of units outstanding were as follows:

	June 30, 2011	December 31, 2010
	(in thousands)	
Common units	5,378	5,363
General partner units	109	109

The outstanding units noted above reflect the retroactive treatment of the reverse unit split described in Note 14, Subsequent Events .

Distributions

The Partnership made distributions of $7.3 million and $5.3 million for the six months ended June 30, 2011 and 2010, respectively. The Partnership made no distributions in respect of our general partner s incentive distribution rights.

In August 2011, the partnership made on aggregate distribution of $33.7 million, on a Prorata basis, to participants in our long-term incentive program holding common units AIM Midstream Holdings and our general Partner. See Note 14 Subsequent Events.

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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 a long-term incentive plan for its employees and consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our general partner adopted an amended and restated long-term incentive plan (as amended, the LTIP). The LTIP currently permits the grant of awards in the form of Partnership units, which may 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 Partnership with respect to a unit during the period such DER is outstanding. At June 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 in advance of our IPO as discussed in Note 14 Subsequent Events .

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

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

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 June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Outstanding at beginning of period	209,824	237,054	205,864	175,236
Granted			19,414	61,818
Converted			(15,454)	
Outstanding at end of period	209,824	237,054	209,824	237,054
Grant date fair value per share	$ 10.00 to $13.67	$ 10.00	$ 10.00 to $13.67	$ 10.00

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 June 30, 2011 and 2010 was $2.2 million and $0.5 million, respectively, and for the six months ended June 30, 2011 and 2010 was $2.7 million and $0.8 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 nonvested awards not yet recognized on June 30, 2011 and December 31, 2010 was $2.4 million and $3.8 million, respectively, and the weighted average period over which this cost is expected to be recognized is approximately 3 years.

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10. Commitments and Contingencies

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.

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

	Payments Due by Period (in thousands)						
	Total	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Operating leases and service contract	$ 2,061	$ 287	$ 415	$ 361	$ 377	$ 367	$ 254
ARO	7,921						7,921
Total	$ 9,982	$ 287	$ 415	$ 361	$ 377	$ 367	$ 8,175

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(in thousands)			
Operating leases	$ 152	$ 211	$ 401	$ 318
ARO		5	8	5
	$ 152	$ 216	$ 409	$ 323

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 June 30, 2011 and 2010, administrative and operational services expenses of $3.4 million and $1.8 million, respectively, were charged to us by our general partner. During the six months ended June 30, 2011 and 2010, administrative and operational services expenses of less than $5.4 million and $3.3 million, respectively, were charged to us by our general partner.

We have 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 provides 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 have 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 June 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 six months ended June 30, 2011 and 2010, less than $0.1 million, had been recorded to selling, general and administrative expenses under this agreement.

As described in Note 14, Subsequent Events , on August 1, 2011 and in connection with our IPO, we terminated the advisory services agreement between our subsidiary, American Midstream, LLC, and affiliates of American

Infrastructure MLP Fund, L.P. 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.

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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:

	Gathering and Processing	Transmission (in thousands)	Total
Three months ended June 30, 2011			
Revenue	$ 49,111	$ 16,919	$ 66,030
Segment gross margin (a),(b)	7,926	2,691	10,617
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	2,602		2,602
Direct operating expenses			3,105
Selling, general and administrative expenses			2,663
Equity compensation expense			2,184
Depreciation expense			5,170
Interest expense			1,281
Net income (loss)			(4,182)

	Gathering and Processing	Transmission (in thousands)	Total
Three months ended June 30, 2010			
Revenue	$ 38,039	$ 9,751	$ 47,790
Segment gross margin (a)	5,639	3,308	8,947
Direct operating expenses			3,346
Selling, general and administrative expenses			1,560
Equity compensation expense			537
Depreciation expense			4,982
Interest expense			1,375
Net income (loss)			(2,853)

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	Gathering and Processing	Transmission (in thousands)	Total
Six months ended June 30, 2011			
Revenue	$ 97,269	$ 36,100	$ 133,369
Segment gross margin (a),(b)	16,167	6,836	23,003
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	(972)		(972)
Direct operating expenses			6,163
Selling, general and administrative expenses			5,152
Equity compensation expense			2,658
Depreciation expense			10,207
Interest expense			2,545
Net income (loss)			(7,692)

	Gathering and Processing	Transmission (in thousands)	Total
Six months ended June 30, 2010			
Revenue	$ 84,663	$ 17,839	$ 102,502
Segment gross margin (a)	11,737	6,958	18,695
Direct operating expenses			6,273
Selling, general and administrative expenses			3,258
Equity compensation expense			791
Depreciation expense			9,948
Interest expense			2,732
Net income (loss)			(4,307)

(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 months ended June 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 six months ended June 30, 2011, $2.6 million and ($1.0) million, respectively, in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized commodity derivative early termination costs. For the three and six months ended June 30, 2011, ($3.0) million in realized gains (losses) were excluded from our Gathering and Processing segment gross margin.

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

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For the purposes of our Gathering and Processing segment, for the three months ended June 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 for our Gathering and processing segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented $7.2 million, $25.7 million and $3.9 million of segment revenue for the three months ended June 30, 2011 and $12.9 million, $5.6 million and $4.3 million for the three months ended June 30, 2010, respectively.

For the six months ended June 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 Gathering and Processing segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented $14.8 million, $54.2 million and $7.7 million of segment revenue for the six months ended June 30, 2011 and $37.1 million, $12.7 million and $10.0 million for the six months ended June 30, 2010, respectively

For the three months ended June 30, 2011 and 2010, Enbridge Marketing (US) L.P., ExxonMobil Corporation and Calpine Corporation represented significant customers, each representing more than 10% of our segment revenue in our Transmision segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ExxonMobil Corporation and Calpine Corporation represented $3.7 million, $10.1 million and $0.9 million of segment revenue for the three months ended June 30, 2011 and $3.6 million, $3.4 million and $1.3 million for the three months ended June 30, 2010, respectively.

For the six months ended June 30, 2011 and 2010, Enbridge Marketing (US) L.P., ExxonMobil Corporation and Calpine 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., ExxonMobil Corporation and Calpine Corporation represented $8.1 million, $19.7 million and $1.7 million of segment revenue for the six months ended June 30, 2011 and $9.1 million, $3.5 million and $2.1 million for the six months ended June 30, 2010, respectively.

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

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

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

We compute earnings per unit using the two-class method. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of 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

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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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net loss attributable to general partner and limited partners	$ (4,182)	$ (2,853)	$ (7,692)	$ (4,307)
Weighted average general partner and limited partner units outstanding(a)(b)	5,634	5,090	5,655	5,070
Earnings per general partner and limited partner unit (basic and diluted)	$ (0.74)	$ (0.56)	$ (1.36)	$ (0.85)
Net loss attributable to limited partners	$ (4,098)	$ (2,796)	$ (7,538)	$ (4,221)
Weighted average limited partner units outstanding(a)(b)	5,525	4,993	5,546	4,973
Earnings per limited partner unit (basic and diluted)	$ (0.74)	$ (0.56)	$ (1.36)	$ (0.85)
Net loss attributable to general partner	$ (84)	$ (57)	$ (154)	$ (86)
Weighted average general partner units outstanding	109	97	109	97
Earnings per general partner unit (basic and diluted)	$ (0.77)	$ (0.59)	$ (1.41)	$ (0.89)

a) Includes unvested phantom units with DER s, which are considered participating securities, of 237,054 as of June 30, 2010. There were no such unvested phantom units with DER s at June 30, 2011.

b) Gives effect to the reverse unit split as described in Note 14, Subsequent Events .

14. Subsequent Events

Initial Public Offering

On August 1, 2011, we closed our IPO of 3,750,000 common units at an offering price of $21 per unit. After deducting underwriting discounts and commissions of approximately $4.9 million paid to the underwriters, estimated offering expenses of approximately $4.1 million and a structuring fee of approximately $0.6 million, the net proceeds from our initial public offering were approximately $69.1 million. We used all of the net offering proceeds from our initial public offering for the uses described in the Prospectus. These uses included the following:

- repayment in full of the outstanding balance under our $85 million credit facility of approximately $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 approximately $5.8 million, on a pro rata basis, to participants in our LTIP holding common units, AIM Midstream Holdings, LLC and our general partner. The distribution to AIM Midstream Holdings and our general partner was a reimbursement for certain capital expenditures incurred with respect to assets previously contributed to us.

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

- each general partner unit held by our general partner reverse split into 0.485 general partner units, resulting in the ownership by our general partner of an aggregate of 108,718 general partner units, representing a 2.0% general partner interest in us;

- each common unit held by participants in our LTIP, reverse split into 0.485 common units, resulting in their ownership of an aggregate of 50,946 common units, representing an aggregate 0.9% limited partner interest in us;

- 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;
- 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; and

- the common units held by AIM Midstream Holdings converted into 801,139 common units and 4,526,066 subordinated units.

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

- AIM Midstream Holdings contributed 76,019 common units to our general partner as a capital contribution, and;

- our general partner contributed the common units contributed to it by AIM Midstream Holdings to us in exchange for 76,019 general partner units in order to maintain its 2.0% general partner interest in us;

New Credit Facility

On August 1, 2011 and immediately following the repayment of the outstanding balance under our $85 million credit facility with net proceeds of the IPO, we terminated our $85 million credit facility, entered into our $100 million credit facility and borrowed approximately $30.0 million under the $100 million revolving credit facility. We used the proceeds from those borrowings to (i) make an aggregate distribution of approximately $27.9 million, on a pro rata basis, to participants in our LTIP holding common units, AIM Midstream Holdings and our general partner and (ii) pay fees and expenses of approximately $2.1 million relating to $100 million revolving credit facility. As of September 8, 2011 we had $30 million in borrowing outstanding under our new credit facility.

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.

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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 for the year ended December 31, 2010 included in our final prospectus dated July 26, 2011 (the Prospectus) and 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 above under the caption Cautionary Statement Regarding Forward-Looking Statements.

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.

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, potentia forecast and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in Item 1A. Risk Factors of this Quarterly Report, our final prospectus dated July 26, 2011 (the Prospectus) filed with the Securities and Exchange Commission pursuant to Rule 424 on July 27, 2011 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;

general economic, market and business conditions; and

the risks described in this Quarterly Report and the Prospectus.

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. We acquired our existing portfolio of assets from a subsidiary of Enbridge Energy Partners, L.P. (Enbridge) in November 2009.

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, or NGLs, under percent-of-proceeds, or POP, arrangements. We own three processing facilities that produced an average of approximately 47.9 Mgal/d and 51.5 Mgal/d of gross NGLs for the three months and six months ended June 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 26.3 Mgal/d and 30.6 Mgal/d of net equity NGL volumes for the three months and six months ended June 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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Recent Developments

Initial Public Offering

On August 1, 2011, we closed our initial public offering of common units (IPO).

For a description of our IPO and the transactions related thereto, please read Note 14 Subsequent Events to our condensed consolidated financial statements included as item 1, Financial Statements of the Quarterly Report.

Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our credit facility evidenced by our credit agreement with a syndicate of lenders, for which Comerica Bank acted as Administrative Agent (our $85 million credit facility), 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 (our $100 million revolving credit facility). Our $100 million revolving credit facility provides for a $100 million revolver. As of September 8, 2011, we had $30.0 million of borrowings outstanding under our $100 million credit facility.

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 for natural gas 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 workovers 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 of this 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 the primary metrics that we use to evaluate our performance. See Non-GAAP Financial Measures. 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 six months ended June 30, 2011, \$2.6 million and \$(1.0) 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 six months ended June 30, 2011, \$3.0 million in realized losses was excluded from gross margin and the Gathering and Processing segment gross margin.

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Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses. 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 and Distributable Cash Flow

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. See Non-GAAP Financial Measures. Although we have not quantified distributable cash flow on a historical basis, after the closing of our IPO we intend to use distributable cash flow, which we define as adjusted EBITDA plus interest income, less cash paid for interest expense and maintenance capital expenditures, to analyze our performance. Distributable cash flow will not reflect changes in working capital balances. Adjusted EBITDA and distributable cash flow are used as supplemental measures 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 unitholders 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.

Note About Non-GAAP Financial Measures

Gross margin, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures will provide useful information to investors in assessing our financial condition and results of operations. Net income is the GAAP measure most directly comparable to each of gross margin and adjusted EBITDA. The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some but not all items that affect the most directly comparable GAAP financial measure. 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.

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. Our expectations are based on assumptions made by us and information currently

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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.

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 required a Prevention of Significant Deterioration, or PSD, permit in 2009 under the federal Clean Air Act, and (iii) our SO2 emission levels may have required reporting under the federal Emergency Planning and Community Right-to-Know Act, or EPCRA, in 2009 and 2010 that was not made. Please read under the caption Business Environmental Matters Air Emissions in the Prospectus for more information about these matters.

We generally emit SO2 from our Bazor Ridge plant only in connection with the flaring of natural gas in situations where the plant is not operational. We do not believe that the elevated levels of SO2 emissions that the plant experienced in 2009 and 2010 resulted from problems with or inefficiencies in our flaring procedures. In response to our discovery of these exceedances, however, we are considering procedural changes to reduce flaring and resulting SO2 emissions when the plant becomes inoperable. We have no plans to install any additional emission controls at our Bazor Ridge plant, as we are unaware of any such controls that could reasonably reduce our SO2 emissions. In addition, we are not aware of further operational restrictions or limitations that would reasonably reduce our SO2 emissions.

Because we flare natural gas at our Bazor Ridge plant only in situations where the plant is not operational, and thus not generating revenue, we do not expect that the potential procedural changes at the Bazor Ridge plant or any operational restrictions or limitations imposed on the plant as a result of these exceedances would materially impact our revenues or results of operations. Please read Liquidity and Capital Resources Impact of Bazor Ridge Emissions Matter for information about the potential effect of these matters on our liquidity and capital resources.

In addition to the potential procedural changes, we may seek an increase in the level of permitted SO2 emissions in order to avoid exceeding our Title V Air Permit in the future. This process involves public comment periods and a technical review. If the application is successful, an amended Title V Air Permit would be issued. This process typically takes approximately nine months to complete. We do not expect that we will be required to suspend or curtail our operations at the Bazor Ridge plant during any such application process.

We do not expect to be required to obtain a PSD permit for the Bazor Ridge plant, as our operation of the plant in 2010 produced SO2 emissions below the threshold requiring such a permit and we expect to continue to operate in this manner. Should we be required to obtain a PSD permit, however, the application process requires modeling, an impact analysis of emissions from the Bazor Ridge plant and a review of possible emission control equipment. The process involves public comment periods and a technical review. If the application is successful, a permit containing site-specific emission limits, as well as monitoring and record-keeping requirements, is issued. The complete process typically takes a year or more to complete. Even if we are required to obtain a PSD permit, we do not expect that we will be required to suspend or curtail our operations at the Bazor Ridge plant during any such application process.

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

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Results of Operations Combined Overview

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Statement of Operations Data:				
Revenue	$ 66,030	$ 47,790	$ 133,369	$ 102,502
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)	
Unrealized gain (loss) on commodity derivatives	2,602		(972)	
Total revenue	65,634	47,790	129,399	102,502
Operating expenses				
Purchases of natural gas, NGLs and condensate	55,413	38,843	110,366	83,807
Direct operating expenses	3,105	3,346	6,163	6,273
Selling, general and administrative expenses	2,663	1,560	5,152	3,258
Equity compensation expense (1)	2,184	537	2,658	791
Depreciation expense	5,170	4,982	10,207	9,948
Total operating expenses	68,535	49,268	134,546	104,077
Operating income (loss)	(2,901)	(1,478)	(5,147)	(1,575)
Interest expense	1,281	1,375	2,545	2,732
Net income (loss)	$ (4,182)	$ (2,853)	$ (7,692)	$ (4,307)
Other Financial Data:				
Adjusted EBITDA (2)	$ 4,852	$ 3,942	$ 11,840	$ 9,137
Gross margin (3)	$ 10,617	$ 8,947	$ 23,003	$ 18,695

(1) Represents cash and non-cash costs related to our LTIP program. Of these amounts, $0.6 million and $0.3 million, for the three months ended June 30, 2011 and 2010, respectively and $0.9 million and $0.6 million for the six months ended June 30, 2011 and 2010, respectively, were non-cash expenses.

(2) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Non-GAAP Financial Measures, and for a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read How We Evaluate Our Operations.

(3) 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.

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

Revenue. Our total revenue in the three months ended June 30, 2011 was $65.6 million compared to $47.8 million in the three months ended June 30, 2010. This increase of $17.8 million was primarily due to higher realized NGL prices and higher throughput volumes in our Gathering and Processing segment and a new fixed-margin contract in our Transmission segment, partially off-set by $0.4 million in realized and unrealized losses associated with our commodity derivatives.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended June 30, 2011 were $55.4 million compared to $38.8 million in the three months ended June 30, 2010. This increase of $16.6 million was primarily due to higher realized NGL prices and higher plant inlet volumes in our Gathering and Processing segment and a new fixed-margin contract in our Transmission segment.

Gross Margin. Gross margin in the three months ended June 30, 2011 was $10.6 million compared to $8.9 million in the three months ended June 30, 2010. This increase of $1.7 million was primarily due to higher realized NGL prices, increased throughput volumes and increased plant inlet volumes in our Gathering and Processing segment.

Direct Operating Expenses. Direct operating expenses in the three months ended June 30, 2011 were $3.1 million compared to $3.3 million in the three months ended June 30, 2010. This decrease of $0.2 million was primarily due to rents, compliance costs and supplies. This decrease was partially offset by an increase in outside service costs.

Selling, General and Administrative Expenses. SG&A expenses in the three months ended June 30, 2011 were $2.7 million compared to $1.6 million in the three months ended June 30, 2010. This increase of $1.1 million was primarily due to increased personnel and benefit costs of $0.6 million, a $0.3 million decrease in costs allocated to capital projects and $0.1 million increase in each of legal fees, outside consulting fees and business development costs. This increase was partially, offset by a decrease of $0.1 million in transition costs associated with the asset purchase from Enbridge.

Equity Compensation Expense. Compensation expense related to the company s LTIP program in the three months ended June 30, 2011 was $2.2 million compared to $0.5 million in the three months ended June 30, 2010. This increase of $1.7 million was primarily due to costs associated with the elimination of the DER provision in existing LTIP agreements. This increase was partially offset by a decrease in DER payments due to phantom unit vesting.

Depreciation Expense. Depreciation expense in the three months ended June 30, 2011 was $5.2 million compared to $5.0 million in the three months ended June 30, 2010. This increase of $0.2 was due to depreciation associated with capital projects placed into service during the period.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Revenue. Our total revenue in the six months ended June 30, 2011 was $129.4 million compared to $102.5 million in the six months ended June 30, 2010. This increase of $26.9 million was primarily due to higher realized NGL prices and higher inlet plant volumes in our Gathering and Processing segment and a new fixed-margin contract in our Transmission segment, partially off-set by $4.0 million in realized and unrealized losses associated with our commodity hedges.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the six months ended June 30, 2011 were $110.4 million compared to $83.8 million in the six months ended June 30, 2010. This increase of $26.6 million was primarily due to higher realized NGL prices and higher plant inlet volumes in our Gathering and Processing segment and a new fixed-margin contract in our Transmission segment. This increase was partially offset by lower realized natural gas prices and the conversion of a fixed margin contract to a transportation contract in our Gathering and Processing segment.

Gross Margin. Gross margin in the six months ended June 30, 2011 was $23.0 million compared to $18.7 million in the six months ended June 30, 2010. This increase of $4.3 million was primarily due to higher realized NGL prices and increased throughput and plant inlet volumes in our Gathering and Processing segment.

Selling, General and Administrative Expenses. SG&A expenses in the six months ended June 30, 2011 were $5.2 million compared to $3.3 million in the six months ended June 30, 2010. This increase of $1.9 million was primarily due to increased personnel and benefit costs of $1.0 million, a $0.3 million decrease in costs allocated to capital projects, $0.3 million increase in accounting and audit fees associated with the carve-out audits of the entities purchased from Enbridge, and $0.1 million increase in regulatory and business development costs. This increase was partially off-set by a decrease of $0.2 million in transition costs associated with the asset purchase from Enbridge.

Equity Compensation Expense. Compensation expense related to the company s LTIP program in the six months ended June 30, 2011 were $2.7 million compared to $0.8 million in the three months ended June 30, 2010. This increase of $1.9 million was primarily due to costs associated with the elimination of the DER provision in existing LTIP agreements. This increase was partially offset by a decrease in DER payments due to phantom unit vesting.

Depreciation Expense. Depreciation expense in the six months ended June 30, 2011 was $10.2 million compared to $9.9 million in the six months ended June 30, 2010. This increase of $0.3 was due to depreciation associated with capital projects placed into service during the period.

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Results of Operations Segment Results

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands, except operating data)			
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$ 49,111	$ 38,039	$ 97,269	$ 84,663
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)	
Unrealized gain (loss) on commodity derivatives	2,602		(972)	
Total revenue	48,715	38,039	93,299	84,663
Purchases of natural gas, NGLs and condensate	41,185	32,401	81,102	72,927
Direct operating expenses	1,684	1,911	3,633	3,866
Other financial data:				
Segment gross margin	7,926	5,639	16,167	11,737
Operating data:				
Average throughput (MMcf/d)	231.3	166.9	237.0	165.6
Average plant inlet volume (MMcf/d) (1)	14.4	7.0	14.8	9.0
Average gross NGL production (Mgal/d) (1)	47.9	22.7	51.5	28.9
Average realized prices:				
Natural gas ($/MMcf)	$ 4.50	$ 4.35	$ 4.22	$ 4.73
NGLs ($/gal)	$ 1.42	$ 1.06	$ 1.34	$ 1.09
Condensate ($/gal)	$ 2.53	$ 1.77	$ 2.38	$ 1.77
Transmission segment				
Financial data:				
Total revenue	$ 16,919	$ 9,751	$ 36,100	$ 17,839
Purchases of natural gas, NGLs and condensate	14,228	6,442	29,264	10,880
Direct operating expenses	1,421	1,435	2,530	2,407
Other financial data:				
Segment gross margin	2,691	3,308	6,836	6,958
Operating data:				
Average throughput (MMcf/d)	314.1	274.1	379.7	317.1
Average firm transportation capacity reservation (MMcf/d)	661.3	620.1	711.7	661.5
Average interruptible transportation throughput (MMcf/d)	73.0	48.2	74.7	64.1

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

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

Gathering and Processing Segment

Revenue. Segment revenue in the three months ended June 30, 2011 was $48.7 million compared to $38.0 million in the three months ended June 30, 2010. This increase of $10.7 million was primarily due to increased throughput on our Quivira system, increased plant inlet volumes primarily at our Bazor Ridge processing plant, higher NGL and condensate sales volumes on our Bazor Ridge System, and higher realized NGL and natural gas prices. This increase in revenue was partially off-set by $0.4 million in realized and unrealized losses associated with our commodity derivatives. Set forth below is a comparison of the volumetric and pricing data for the three months ended June 30, 2011 and 2010, as well as a summary of the effect of the commodity derivative transactions that we entered into in January and June 2011.

Total natural gas throughput volumes on our Gathering and Processing segment were 231.3 MMcf/d in the three months ended June 30, 2011 compared to 166.9 MMcf/d in the three months ended June 30, 2010. Natural gas inlet volumes at our owned processing plants were 14.4

MMcf/d in the three months ended June 30, 2011 compared to 7.0 MMcf/d in the three months ended June 30, 2010. Gross NGL production volumes from our owned processing plants were 47.9 Mgal/d in the three months ended June 30, 2011 compared to 22.7 Mgal/d in the three months ended June 30, 2010.

The average realized price of natural gas in the three months ended June 30, 2011 was $4.50/Mcf, compared to $4.35/Mcf in the three months ended June 30, 2010. The average realized price of NGLs in the three months ended June 30, 2011 was $1.42/gal, compared to $1.06/gal in the three months ended June 30, 2010. The average realized price of condensate in the three months ended June 30, 2011 was $2.53/gal, compared to $1.77/gal in the three months ended June 30, 2010.

We entered into swap and put contracts in January 2011 and swap contracts again in June 2011. These commodity derivative transactions had a positive net effect of $2.6 million on our revenue related to unrealized losses for the three months ended June 30, 2011. We had no commodity derivatives during the three months ended June 30, 2010. 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 entered into new swap contracts 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 three months ended June 30, 2011.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2011 were $41.2 million compared to $32.4 million for the three months ended June 30, 2010. This increase of $8.8 million was primarily due to higher realized natural gas and NGL prices in addition to higher NGL and condensate volumes.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2011 was $7.9 million compared to $5.6 million for the three months ended June 30, 2010. This increase of $2.3 million was primarily due to increased throughput on our Quivira and Bazor Ridge systems and higher realized NGL prices that positively affected our Gloria and Bazor Ridge systems. This increase was partially offset by higher realized natural gas prices which negatively impacted processing margins on our Gloria System. Segment gross margin for the Gathering and Processing segment represented 74.3% of our gross margin for the three months ended June 30, 2011, compared to 63.0% for the three months ended June 30, 2010.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2011 were $1.7 million compared to $1.9 million for the three months ended June 30, 2010. This decrease of $0.2 million was primarily due to decreased due to rents, compliance costs and supplies.

Transmission Segment

Revenue. Segment revenue for the three months ended June 30, 2011 was $16.9 million compared to $9.8 million for the three months ended June 30, 2010. Total natural gas throughput on our Transmission systems for the three months ended June 30, 2011 was 314.1 MMcf/d compared to 274.1 MMcf/d in the three months ended June 30, 2010. This increase of $7.1 million in revenue was primarily due to the 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 three months ended June 30, 2011 and we had no commodity derivatives during the three months ended June 30, 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2011 were $14.2 million compared to $6.4 million for the three months ended June 30, 2010. This increase of $7.8 million was primarily due to the new fixed-margin contract.

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Segment Gross Margin. Segment gross margin for the three months ended June 30, 2011 was $2.7 million compared to $3.3 million for the three months ended June 30, 2010. This decrease of $0.6 million was primarily due to additional transportation fees recognized in the second quarter of 2010. Segment gross margin for the Transmission segment represented 25.3% of our gross margin for the three months ended June 30, 2011, compared to 37.0% for the three months ended June 30, 2010.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Gathering and Processing Segment

Revenue. Segment revenue in the six months ended June 30, 2011 was $93.3 million compared to $84.7 million in the six months ended June 30, 2010. This increase of $8.6 million was primarily due to increased throughput on our Gloria and Quivira systems, increased plant inlet volumes primarily at our Bazor Ridge processing plant, higher NGL sales and condensate volumes on our Bazor Ridge and Gloria Systems, and higher realized NGL prices. This increase was partially offset by lower realized natural gas prices and the conversion of a fixed margin contract to a transportation contract on one of our other systems as well as $4.0 million in realized and unrealized losses associated with our commodity derivatives. Set forth below is a comparison of the volumetric and pricing data for the six months ended June 30, 2011 and 2010, as well as a summary of the effect of the commodity derivative transactions that we entered into in January and June 2011.

Total natural gas throughput volumes on our Gathering and Processing segment were 237.0 MMcf/d in the six months ended June 30, 2011 compared to 165.6 MMcf/d in the six months ended June 30, 2010. Natural gas inlet volumes at our owned processing plants were 14.8 MMcf/d in the six months ended June 30, 2011 compared to 9.0 MMcf/d in the six months ended June 30, 2010. Gross NGL production volumes from our owned processing plants were 51.5 Mgal/d in the six months ended June 30, 2011 compared to 28.9 Mgal/d in the six months ended June 30, 2010.

The average realized price of natural gas in the six months ended June 30, 2011 was $4.22/Mcf, compared to $4.73/Mcf in the six months ended June 30, 2010. The average realized price of NGLs in the six months ended June 30, 2011 was $1.34/gal, compared to $1.09/gal in the six months ended June 30, 2010. The average realized price of condensate in the six months ended June 30, 2011 was $2.38/gal, compared to $1.77/gal in the six months ended June 30, 2010.

We entered into a series of swap and put transactions in January 2011 and swap transactions again in June 2011. These commodity derivative transactions had a negative net effect of $1.0 million on our revenue related to unrealized losses for the six months ended June 30, 2011. We had no commodity derivatives during the three months ended June 30, 2010. For a discussion of our hedge 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 six months ended June 30, 2011.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2011 were $81.1 million compared to $72.9 million for the six months ended June 30, 2010. This increase of $8.2 million was primarily due to higher realized NGL prices and higher plant inlet volumes at the Bazor Ridge processing plant and was partially offset by lower natural gas prices and the conversion of a fixed margin contract to a transportation contract on one of our systems.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2011 was $16.2 million compared to $11.7 million for the six months ended June 30, 2010. This increase of $4.5 million was primarily due to increased throughput on our Gloria, Quivira and Bazor Ridge systems, higher realized NGL prices that positively affected our Gloria, Quivira and Bazor Ridge systems, higher realized NGL prices that positively affected our Gloria and Bazor Ridge systems, and lower realized natural gas prices which positively impacted processing margins on our Gloria system. Segment gross margin for the Gathering and Processing segment represented 70.0% of our gross margin for the six months ended June 30, 2011, compared to 62.8% for the six months ended June 30, 2010.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2011 were $3.7 million compared to $3.9 million for the six months ended June 30, 2010, with a net decrease of $0.2 million. There were no significant changes in any individual expense type.

Transmission Segment

Revenue. Segment revenue for the six months ended June 30, 2011 was $36.1 million compared to $17.8 million for the six months ended June 30, 2010. Total natural gas throughput on our Transmission systems for the six months ended June 30, 2011 was 379.7 MMcf/d compared to 317.1 MMcf/d in the six months ended June 30, 2010. This increase of $18.3 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 derivative transactions had no effect on segment revenue for the six months ended June 30, 2011 and we had no commodity derivatives during the six months ended June 30, 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2011 were $29.3 million compared to $10.9 million for the six months ended June 30, 2010. This increase of $18.4 million was primarily due to the new fixed-margin contract.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2011 was $6.8 million compared to $7.0 million for the six months ended June 30, 2010. This decrease of $0.2 million was primarily due to slightly lower realized margins on our MLGT system and one of our other small systems and lower authorized overrun transportation gross margin realized on our regulated pipelines on high demand days, partially offset by margin from a new customer contract on one of our other, smaller systems. Segment gross margin for the Transmission segment represented 29.7% of our gross margin for the six months ended June 30, 2011, compared to 37.2% for the six months ended June 30, 2010.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2011 were $2.5 million compared to $2.4 million for the six months ended June 30, 2010, or an increase of $0.1 million. There was no significant change in any individual expense type.

Liquidity and Capital Resources

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

The principal indicators of our liquidity at June 30, 2011 were our cash on hand and availability under our $85 million credit facility as discussed below. As of June 30, 2011, our available liquidity was $11.0 million, comprised of cash on hand of less than $0.1 million and $10.9 million available under our $85 million credit facility. Subsequent to June 30, 2011 and concurrently with closing of our IPO, we closed on our $100 million revolving credit facility. As of September 8, 2011, we had approximately $70 million of borrowing capacity under our $100 million revolving credit facility.

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 (i) the minimum quarterly distribution on all of our outstanding common and subordinated units and (ii) 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.

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 ($8,856) million at June 30, 2011. Our negative working capital position was in large part due to the amortization requirement of the then existing $85 million credit facility. On August 1, 2011 we entered into a new $100 million revolving credit facility which has no such amortization requirement.

Cash Flows

The following table reflects cash flows for the applicable periods:

	Six Months Ended June 30, 2011	2010
Net cash provided by (used in):		
Operating activities	$ 5,770	$ 8,414
Investing activities	(2,382)	(2,371)
Financing activities	(3,389)	(6,318)

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Operating Activities. Net cash provided by (used in) operating activities was $5.8 million for the six months ended June 30, 2011 compared to $8.4 million for the six months ended June 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 and $1.5 million was used to pay holders of phantom units under our LTIP in in consideration for the elimination of the DER provision in existing LTIP agreements.

Investing Activities. Net cash provided by (used in) investing activities was ($2.4) million for the six months ended June 30, 2011 compared to ($2.4) million for the six months ended June 30, 2010. Cash provided by (used in) investing activities for the six months ended June 30, 2011 was primarily a result of $0.7 million used for the addition of a master meter station on our MLGT System and $0.6 million used for federally mandated levee improvements on our Gloria System.

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Financing Activities. Net cash provided by (used in) financing activities was ($3.4) million for the six months ended June 30, 2011 compared to ($6.3) million for the six months ended June 30, 2010. The change in cash provided by (used in) financing activities was primarily a result of unitholder distributions, offset in part by borrowings under our credit facility.

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 six months ended June 30, 2011, our capital expenditures totaled $1.6 million and $2.9 million, respectively. For this period, capital expenditures included maintenance capital expenditures and expansion capital expenditures. We estimate that 38% of our capital expenditures, or $0.6 million, were maintenance capital expenditures and that 14% of our capital expenditures, or $0.2 million, were expansion capital expenditures. Although we classified our capital expenditures as maintenance capital expenditures 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 anticipated to be outstanding immediately after the closing of this offering, 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.

Our $100 Million Revolving Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our $85 million 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 revolving 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 (our $100 million revolving credit facility). As of September 8, 2011, we had $30.0 million of borrowings outstanding under our $100 million revolving credit facility.

We utilized a portion of the draws from our $100 million revolving credit facility to (i) make an aggregate distribution of approximately $27.9 million, on a pro rata basis, to participants in our LTIP holding common units, AIM Midstream Holdings and our general partner and (ii) pay fees and expenses of approximately $2.1 million relating to our $100 million revolving 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.

Contractual Obligations

As of June 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.

Non-GAAP Financial Measures

We include in this Quarterly Report the non-GAAP financial measures of adjusted EBITDA and gross margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP.

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Adjusted EBITDA

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.

Adjusted EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors and lenders, 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 unitholders 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.

The economic rationale behind management s use of adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The GAAP measure most directly comparable to adjusted EBITDA is net income. Our non-GAAP financial measure of adjusted EBITDA should not be considered as an alternative to net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of adjusted EBITDA may not be comparable to similarly titled measures of other companies.

Management compensates for the limitations of adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management s decision-making process.

The following table presents a reconciliation of adjusted EBITDA to net income (loss) attributable to our unitholders for each of the periods indicated:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income	(4,182)	(2,853)	(7,692)	(4,307)
Add:				
Depreciation expense	5,170	4,982	10,207	9,948
Interest expense	1,281	1,375	2,545	2,732
Realized gain (loss) on early termination of commodity derivatives	2,998		2,998	
Unrealized gain (loss) on commodity derivatives	(2,602)		972	
Non-cash equity compensation expense	570	305	905	557
Special distribution to holders of LTIP phantom units	1,624		1,624	
One-time transaction costs	(7)	133	281	207
Adjusted EBITDA	4,852	3,942	11,840	9,137

Gross Margin

We define gross margin as the sum of segment gross margin in our Gathering and Processing segment and segment gross margin in our Transmission segment. 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. 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. Gross margin is included as a supplemental disclosure because it is a primary performance measure used by our management as it represents the results of service fee revenue and cost of sales, which are key components of our operations. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income 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. 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 six months ended June 30, 2011, $2.6 million and ($1.0) million, respectively, in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized commodity derivative early termination costs. For the three and six months ended June 30, 2011, ($3.0) million in realized gains (losses) were excluded from our Gathering and Processing segment gross margin. For a reconciliation of gross margin to net income, it s 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.

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 No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, requires additional disclosures with regard to fair value measurements categorized within Level 3 of the fair value hierarchy. Early adoption is not permitted.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, stipulates the financial statement presentation requirements for other comprehensive income.

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 our unaudited condensed consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

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 June 30, 2011, we had hedged approximately 85% 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 June 30, 2011:

Commodity	Period	Notional Volumes (gal/d)	Weighted Average Price ($/gal) We Receive	Weighted Average Price ($/gal) We Pay	Fair Market Value June 30, 2011
Ethane	July 2011 - Dec 2012	7,300	$ 0.57	OPIS avg	(294,348)
Propane	July 2011 - Dec 2012	7,050	$ 1.40	OPIS avg	(73,953)
Iso-Butane	July 2011 - Dec 2012	2,510	$ 1.81	OPIS avg	(16,238)
Normal Butane	July 2011 - Dec 2012	3,000	$ 1.74	OPIS avg	(426)
Natural Gasoline	July 2011 - Dec 2012	5,500	$ 2.31	OPIS avg	(109,093)
Total		25,360	$ 1.44		(494,058)

In January 2011, we entered into a put arrangement under which we receive a fixed floor price of $1.29 per gallon on 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 June 30, 2011:

Commodity	Period	Notional Volumes (gal/d)	Floor Strike Price ($/gal)	Fair Market Value June 30, 2011
NGL basket	Feb 2011 to July 2012	9,800	$ 1.29	192,229

Interest Rate Risk

During the six months ended June 30, 2011, we had exposure to changes in interest rates on our indebtedness associated with our $85 million credit facility. In December 2009, we entered into an interest rate cap with participating lenders with a $23.5 million notional amount at June 30, 2011 that effectively capped our Eurodollar-based rate exposure on that portion of our debt at a maximum of 4.0%. We anticipate that, in conjunction with our entry into a new credit facility contemporaneous with the closing of the IPO, we will implement similar swap or cap structures 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 $0.3 million for the six months ended June 30, 2011.

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

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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 June 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 June 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 II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please read under the captions " Regulation of Operations Interstate Transportation Pipeline Regulation and Environmental Matters in our 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 approximately $4.9 million paid to the underwriters, estimated offering expenses of approximately $4.1 million and a structuring fee of approximately $0.6 million, the net proceeds from our IPO were approximately $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 approximately $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 approximately $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 $100 million credit facility, entered into our $100 million revolving credit facility and borrowed approximately $30.0 million. We used the proceeds from those borrowings to (i) make an aggregate distribution of approximately $27.9 million, on a pro rata basis, to participants in our long-term incentive plan holding common units, AIM Midstream Holdings and the General Partner and (ii) pay fees and expenses of approximately $2.1 million relating to $100 million 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 June 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 June 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 June 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 June 30, 2011 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema Document.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith

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

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SIGNATURES

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

Date: September 9, 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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