American Midstream Partners, LP
Form 10-K
March 19, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

Or

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

For the fiscal year ended December 31, 2011

For the transition period from to

Commission File Number: 001-35257

AMERICAN MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**27-0855785**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1614 15th Street, Suite 300	
Denver, CO	**80202**
(Address of principal executive offices)	**(Zip code)**

(720) 457-6060

(Registrant s telephone number, including area code)

Securities registered pursuant to section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange of Which Registered**
Common Stock	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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

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

Indicate by checkmark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained in, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

There were 4,528,208 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of February 29, 2012. Our common units trade on the New York Stock Exchange under the ticker symbol AMID.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, could, project, believe, anticipate, expect, estimate, potential, plan, 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 as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; and

general economic, market and business conditions.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual 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 Annual Report on Form 10-K (the Annual Report). Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

As generally used in the energy industry and in this Annual Report, the identified terms have the following meanings:

As used in this Annual 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.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf/d: One billion cubic feet per day.

condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

end-use markets: The ultimate users and consumers of transported energy products.

FERC: Federal Energy Regulatory Commission.

gal: One gallon.

gal/d: One gallon per day.

Mcf: One thousand cubic feet.

Mgal/d: One thousand gallons per day.

MMBbl/d: One million stock tank barrels per day.

MMBtu: One million British Thermal Units.

MMBtu/d: One million British Thermal Units per day.

MMcf: One million cubic feet.

MMcf/d: One million cubic feet per day.

NGA: Natural Gas Act of 1938.

NGLs: Natural gas liquids. The combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

OPIS: Oil Price Information Service.

play: A proven geological formation that contains commercial amounts of hydrocarbons.

receipt point: The point where production is received by or into a gathering system or transportation pipeline.

residue gas: The natural gas remaining after being processed or treated.

tailgate: Refers to the point at which processed natural gas and natural gas liquids leave a processing facility for end-use markets.

Tcf: One trillion cubic feet.

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

wellhead: The equipment at the surface of a well used to control the well s pressure; also, the point at which the hydrocarbons and water exit the ground.

WTI: West Texas Intermediate, a type of crude oil commonly used as a price benchmark.

PART I

Item 1. Business

Overview

We are a growth-oriented Delaware limited partnership that was formed by 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 and a 50% non-operating interest in a fourth plant, two interstate pipelines and five intrastate pipelines. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 1,400 miles of pipelines that gather and transport over 500 MMcf/d of natural gas.

Our operations are organized into two segments: (i) Gathering and Processing and (ii) Transmission. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, transporting and treating natural gas. Where we provide processing services at the plants that we own or share an interest, or obtain processing services for our own account under our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and/or resulting NGLs under percent of proceeds (POP) arrangements. We own three processing facilities that collectively produced an average of approximately 52.6 Mgal/d and 34.1 Mgal/d of gross NGLs for years ended December 31, 2011 and 2010, respectively. Effective November 1, 2011, we acquired a 50% undivided non-operating interest in the Burns Point Plant which produced 11.3 Mgal/d to our account in 2011, during our period of ownership. In addition, in connection with our elective processing arrangements, we contract for processing capacity at a third-party plant where we have the option to process natural gas that we purchase. Under these arrangements, we sold an average of approximately 27.4 Mgal/d and 28.1 Mgal/d of net equity NGL volumes for the years ended December 31, 2011 and 2010, respectively. 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.

For the years ended December 31, 2011 and 2010, we generated \$46.2 million and \$38.1 million of gross margin, respectively, of which \$32.5 million and \$24.6 million, respectively, was segment gross margin generated in our Gathering and Processing segment and \$13.7 million and \$13.5 million, respectively, was segment gross margin generated in our Transmission segment. For the years ended December 31, 2011 and 2010, \$27.1 million and \$24.9 million, or 58.7% and 65.4%, respectively, of our gross margin was generated from fee-based, fixed-margin and firm and interruptible transportation contracts with respect to which we have little or no direct commodity price exposure. For a definition of gross margin and a reconciliation of gross margin to its most directly comparable financial measure calculated in accordance with GAAP, please read Selected Historical Financial and Operating Data Non-GAAP Financial Measures.

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business. We expect to achieve this objective by executing the following strategies:

- ***Capitalize on Organic Growth Opportunities Associated with Our Existing Assets.*** We continually seek to identify and evaluate economically attractive organic expansion and asset enhancement opportunities that leverage our existing asset footprint and strategic relationships with our customers. We expect to have opportunities to expand our systems into new markets and sources of supply, which we believe will make our services more attractive to our customers. We intend to focus on projects that can be completed at a relatively low cost and have potential for attractive returns.

- ***Attract Additional Volumes to Our Systems.*** We intend to attract new volumes of natural gas to our systems from existing and new customers by continuing to provide superior customer service and aggressively marketing our services to additional customers in our areas of operation. In addition, we intend to rebuild or reestablish relationships with customers that were potentially underserved by the previous owner of our assets. For example, in 2010 we were able to contract with a customer on our Gloria system for volumes of natural gas that it had decided to have gathered and processed by alternative means prior to our acquisition of the system. We have available capacity on a majority of our systems, and as a result, we can accommodate additional volumes at a minimal incremental cost.

Pursue Strategic and Accretive Acquisitions. We plan to pursue accretive acquisitions of energy infrastructure assets that are complementary to our existing asset base or that provide attractive returns in new operating regions or business lines. We will pursue acquisitions in our areas of operation that we believe will allow us to realize operational efficiencies by capitalizing on our existing infrastructure, personnel and customer relationships. We will also seek acquisitions in new geographic areas or new but related business lines to the extent that we believe we can utilize our operational expertise to enhance our business with these acquisitions. For example, in November, 2011, we acquired from Marathon Oil Company a fifty percent (50%) non-operating working interest in the Burns Point Plant. The Burns Point Plant is located in St Mary Parish, LA and to which our Quivira Gathering system is connected.

Manage Exposure to Commodity Price Risk. We will manage our commodity price exposure by targeting a contract portfolio that is weighted towards firm transportation, fee-based and fixed-margin contracts while mitigating direct commodity price exposure by employing a prudent hedging strategy. For the years ended December 31, 2011 and 2010, approximately 58.7% and 65.4%, respectively, of our gross margin was generated from firm transportation, fee-based and fixed-margin contracts that, together with our percent-of-proceeds contracts and hedging activities, generated relatively stable cash flows. For the year ending December 31, 2012, we have hedged 87%, respectively, of our expected net equity NGL volumes with a combination of swaps and puts for the specific NGL components to which we are exposed. With respect to our exposure to natural gas prices, we are currently long natural gas on certain of our systems and short natural gas on certain of our other systems, which effectively creates a natural hedge against our exposure to fluctuations in the price of natural gas.

Maintain Financial Flexibility and Conservative Leverage. We plan to pursue a disciplined financial policy and seek to maintain a conservative capital structure that we believe will allow us to consider attractive growth projects and acquisitions even in challenging commodity price or capital markets environments.

Continue our Commitment to Safe Environmentally Sound Operations. The safety of our employees and the communities in which we operate is one of our highest priorities. We believe it is critical to handle natural gas and NGLs for our customers safely, while striving to minimize the environmental impact of our operations. To this end, we implemented a safety performance program, including an integrity management program, upon our formation in 2009 and implemented planned maintenance programs to increase the safety, reliability and efficiency of our operations.

Develop strategic and accretive new asset platforms. We plan selectively to pursue the development of new complementary midstream asset platforms in our current operating regions and in new midstream assets in regions where we currently do not have any assets that provide attractive returns. We believe it is important to our current customers that we act as their midstream partner beyond our current asset footprint, so it is important to have the ability to develop new infrastructure for our customers where they deem it necessary in an accretive and economically attractive manner. As our customers move to produce new areas or develop new end use markets, we seek to provide solutions for their midstream needs. We will develop assets in our current lines of business, but may pursue opportunities in new but related business lines as well.

Competitive Strengths

We believe that we will be able to successfully execute our business strategies because of the following competitive strengths:

Well Positioned to Pursue Opportunities Overlooked by Larger Competitors. Our size and flexibility, in conjunction with our geographically diverse asset base, positions us to pursue economically attractive growth projects and acquisitions that may not be large enough to be attractive to many of our larger competitors. Given the current size of our business, these opportunities may have a larger impact on us than they would have on our competitors and may provide us with material growth opportunities. In addition, as a result of our focus on customer service, we believe that we have unique insights into our customers needs and are well situated to take advantage of organic growth opportunities that arise from those needs. The benefits of our size and flexibility apply not only to the opportunities around our current assets but to opportunities to develop new asset platforms as well, where we can pursue the development of a new system that will be an impactful new asset to our company that would not be meaningful enough to gain the attention of our larger competitors.

Diversified Asset Base. Our assets are diversified geographically and by business line, which contributes to the stability of our cash flows and creates a number of potential growth avenues for our business. We primarily operate in five states, have access to multiple sources of natural gas supply and service various interstate and intrastate pipelines as well as utility, industrial and other commercial customers. We believe this diversification provides us with a variety of growth opportunities and mitigates our exposure to reduced activity in any one area.

Strategically Located Assets. Our assets are located in areas where we believe there will be opportunities to access new natural gas supplies and to capture new customers that are underserved by our competitors. We continue to see drilling activity on and around our systems, and we believe that our assets are strategically positioned to capitalize on the resurgent drilling activity, increased demand for midstream services and growing commodity consumption in the Gulf Coast and Southeast U.S. regions. This belief is based on:

- the proximity of our gathering and transmission systems to newly producing wells and the relatively lower cost to connect to our systems compared to those farther away;

- the available capacity of our systems, coupled with an ability to add capacity economically to our systems; and

- the fact that many of our systems have multiple downstream interconnects that provide our customers with multiple market delivery options, thus causing our systems to be more attractive versus those of our competitors.

Focus on Delivering Excellent Customer Service. We view our strong customer relationships as one of our key assets and believe it is critical to maintain operational excellence and ensure best-in-class customer service and reliability. Furthermore, we believe our entrepreneurial culture and smaller size relative to our peers enables us to offer more customized and creative solutions for our customers and to be more responsive to their needs. We believe our customer focus will enable us to capture new opportunities and expand into new markets.

Experienced and Incentivized Management and Operating Teams. Our executive management team has an average of over 25 years of experience in the midstream energy industry. The team possesses a comprehensive skill set to support our business and enhance unitholder value through asset optimization, accretive development projects and acquisitions. In addition, our field supervisory team has operated our assets for an average of over 20 years. We believe that our field employees knowledge of the assets will further contribute to our ability to execute our business strategies. Furthermore, the interests of our executive management and operating teams are strongly aligned with those of common unitholders, including through their ownership of common units and our Long-Term Incentive Plan.

Our Assets

We own and operate nine gathering systems, three processing facilities, two interstate pipelines and five intrastate pipelines. We also own a 50% undivided interest in the Burns Point Plant, a natural gas processing plant. Our assets are primarily located in Alabama, Louisiana, Mississippi, and Texas. We organize our operations into two business segments: (i) Gathering and Processing; and (ii) Transmission. The following table provides information regarding our segments and assets as of December 31, 2011 and for the years ended December 31, 2011 and 2010.

	System Type	Contract Type (a)	Miles	Approximate Number of Connected Wells / Receipt Points	Compression (Horsepower)	Approximate Design Capacity (MMcf/d)	Approximate Average Throughput (MMcf/d) Year Ended December 31, 2011	2010
Gathering and Processing								
Gloria	Gathering, Processing(b)	Fee(e), POP	110	59	1,877	60	43.3	36.6
Lafitte	Gathering	Fee(e)	40	44		71	19.3	12.0
Bazor Ridge	Gathering, Processing	Fee, POP	160	42	6,287	22	13.4	9.2
Quivira	Gathering	Fee	34	17		140	110.8	77.4
Burns Point Plant(f)	Processing	POP		3	11,000	200	21.8(g)	
Offshore Texas	Gathering	Fee(e)	56	23		100	18.2	15.3
Other (c)	Gathering, Processing	Fee(e), POP	189	445	5,156	153	24.1	25.1
Gathering and Processing total			589	633	24,320	746	250.9	175.6
Transmission								
Bamagas	Intrastate	FT	52	2		450	163.9	151.5
AlaTenn	Interstate	FT, IT	295	4	3,665	200	46.0	48.0
Midla	Interstate	FT, IT	370	9	3,600	198	95.1	87.2
MLGT	Intrastate	FT, IT(e)	54	7		170	51.9	50.5
Other(d)	Intrastate	FT, IT	82	6		336	24.2	13.0
Transmission total			853	28	7,265	1,354	381.1	350.2

(a) In this table, fee refers to fee-based contracts, POP refers to percent-of-proceeds contracts, FT refers to firm transportation contracts and IT refers to interruptible transportation contracts.

(b)

Although the Gloria system is comprised solely of gathering pipelines, we generate a substantial portion of our Gloria revenue by processing natural gas for our own account at the Toca processing plant in connection with our elective processing arrangements. We do not own the Toca processing plant, but we have the contractual ability to process the natural gas for our own account and retain the majority of the proceeds derived from the sale of the residue natural gas and resulting NGLs. Please see Gathering and Processing Segment Gloria System.

(c) Includes our Alabama Processing, Fayette, Magnolia, Stringer and Heidelberg systems.

(d) Includes our Trigas, Owens Corning and Chalmette systems.

(e) Because we view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements in our Gathering and Processing segment and the fee earned in our interruptible transportation arrangements in our Transmission segment, we have included the fixed-margin arrangements in those categories.

(f) The Burns Point Plant is connected to 3 pipelines, including the Quivira System, which are supported by over 40 wells and central delivery points.

(g) Reflects operating performance beginning November 1, 2011 which was the effective date of our ownership interest in the Burns Point Plant.

Gathering and Processing Segment

General

Our Gathering and Processing segment is an integrated midstream natural gas system that provides the following services to our customers:

- gathering;
- compression;
- treating;

processing;

transportation; and

sales of natural gas, NGLs and condensate.

We own one processing plant on our Bazor Ridge system and two on our Alabama Processing system. In addition, we own a 50% non-operating interest in the Burns Point Plant and have the right to contract for processing services for our own account at plant that is connected to our Gloria system, the Toca plant,. The Toca plant is owned and operated by Enterprise Products Partners, LP (Enterprise) which also operates the Burns Point Plant. Our Bazor Ridge processing plant, the Burns Point plant and the Toca plant are all cryogenic processing plants. These types of processing plants represent the latest generation of processing techniques, using extremely low temperatures and high pressures to optimize the extraction of NGLs from the raw natural gas stream.

We generally derive revenue in our Gathering and Processing segment from fee-based, fixed-margin and POP arrangements, whether for our producer and supplier customers or our own account. We have no keep-whole arrangements with our customers. On our Gloria, Lafitte and Offshore Texas systems, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and subsequently transport that natural gas to delivery points on our systems at which we sell the natural gas at the same undiscounted index price thereby earning a fixed margin on each transaction. We regard the segment gross margin we earn with respect to those purchases and sales a fixed-margin and as the economic equivalent of a fee for our transportation service, and as such, we include these transactions in the category of fee-based contractual arrangements. In order to minimize commodity price risk we face in these transactions, we match sales with purchases at the index price on the date of settlement. For the year ended December 31, 2011, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 41.2% and 58.8%, respectively, of our segment gross margin for this segment. For the year ended December 31, 2010, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 46.3% and 53.7%, respectively, of our segment gross margin for this segment.

We continually seek new sources of raw natural gas supply to maintain and increase the throughput volume on our gathering systems and through our processing plants. As a result, we connected six new supply sources in 2011 to systems in our Gathering and Processing segment, including connections of individual wells, as well as central delivery points and interstate and intrastate pipelines that have multiple wells behind them.

Our Gathering and Processing assets are located in Alabama, Louisiana and Mississippi and in shallow state and federal waters in the Gulf of Mexico off the coasts of Louisiana and Texas.

Gloria System

The Gloria gathering system provides gathering and compression services through our assets, as well as processing services through our elective processing arrangements. The Gloria system is located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana and consists of approximately 110 miles of pipeline with diameters ranging from three to 16 inches and three compressors with a combined size of 1,877 horsepower. The Gloria system has a design capacity of approximately 90 MMcf/d, but is currently limited by compression horsepower at the Gloria Compressor Station to approximately 60 MMcf/d. Average throughput on the Gloria system for the year ended December 31, 2010 was 36.6 MMcf/d from approximately 57 connected wells and an interconnect with our Lafitte system. Average throughput on the Gloria system increased to approximately 43.3 MMcf/d from 59 connected wells for the year ended December 31, 2011 due to excess volumes from our Lafitte system, primarily resulting from the completion of a new interconnect between the Lafitte system and TGP, an interstate pipeline owned by El Paso Corporation. For more information about the excess natural gas from our Lafitte system, please read Lafitte System.

The Gloria system gathers natural gas from onshore oil and natural gas wells producing from the Gulf Coast region of Louisiana. Production is derived from a variety of reservoirs and ranges from dry natural gas to rich associated natural gas. Well decline rates are variable in this area, but it is common practice for producers to mitigate declines in production with workovers and re-completions of existing wells. An average of three wells per year were connected to the Gloria system over the last three years, with two wells connected during the year ended December 31, 2011. Producers generally bear the cost of connecting their wells to our Gloria system.

Toca Plant and Our Elective Processing Arrangements. 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 and operated by Enterprise. We entered into a new POP processing contract with Enterprise in July 2011 that replaced two month-to-month POP processing contracts with Enterprise and allows us to continue to process raw natural gas through the Toca plant, whether for our customers or our own account. This new contract has an initial term of seven years and covers volumes from both our Gloria and Lafitte systems. The new contract contains a tiered-pricing structure based on the volume of natural gas processed under which Enterprise retains a percentage of the NGLs produced by the Toca plant as payment for its processing services.

Natural gas that is processed at the Toca plant is transported to end users via the Sonat pipeline directly and through various interconnects downstream of the Toca plant. Sonat is the primary pipeline into which Toca volumes are currently delivered. Sonat has agreed to sell its Gulf of Mexico gathering facilities located upstream of the Toca Plant to High Point Gas Transmission, LLC.

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. Due to currently strong processing margins, we currently process 100% of the natural gas purchased on the Gloria system, as well as any excess natural gas purchased via the Lafitte/TGP interconnect in excess of the needs of ConocoPhillips at the Alliance Refinery. Based on publicly available information, we believe that the Toca plant has sufficient capacity available to accommodate additional volumes from the Gloria system.

Lafitte System

The Lafitte gathering system consists of approximately 40 miles of gathering pipeline, with diameters ranging from four to 12 inches and a design capacity of approximately 71 MMcf/d. The Lafitte system originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana at the Alliance Refinery owned by ConocoPhillips Corporation, or ConocoPhillips. Average throughput on the Lafitte system for the years ended December 31, 2011 and 2010 was 19.3 MMcf/d and 12.0 MMcf/d, respectively, from approximately 44 connected wells and an interconnect with TGP that was completed in December 2010. We are the sole supplier of natural gas to the Alliance Refinery through our Lafitte and Gloria systems. We supply natural gas to the Alliance Refinery pursuant to a long-term contract that expires in 2023. Any natural gas not used by ConocoPhillips at the Alliance Refinery is delivered to our Gloria system.

Like our nearby Gloria system, the Lafitte system gathers natural gas from onshore oil and natural gas wells producing from the Gulf Coast region of Louisiana. An average of one well per year was connected to the Lafitte system over the last three years, with no wells connected during the year ended December 31, 2011. Producers generally bear the cost of connecting their wells to our Lafitte system.

TGP Interconnect. In December 2010, we completed an interconnect between our Lafitte pipeline and the TGP interstate system. This interconnect provides a redundant source of natural gas supply for the ConocoPhillips Alliance Refinery to the extent that the Lafitte native production is insufficient to supply the needs of the refinery and provides us with increased operational flexibility on our Gloria and Lafitte systems. To the extent that there is excess supply that the refinery does not consume, we purchase those volumes to be sold into Sonat pursuant to a fixed-margin arrangement or to be processed at the Toca processing facility pursuant to elective processing arrangements.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 160 miles of pipeline with diameters ranging from three to eight inches and three compressor stations with a combined compression capacity of 1,069 horsepower. Our Bazor Ridge system is located in Jasper, Clarke, Wayne and Greene Counties of Mississippi. The Bazor Ridge system also contains a sour natural gas treating and cryogenic processing plant located in Wayne County, Mississippi with a design capacity of approximately 22 MMcf/d and four inlet and one discharge compressor with approximately 5,218 of combined horsepower. We upgraded the turbo expander at the Bazor Ridge processing plant in June 2010, which resulted in a significant improvement in the plant s NGL recoveries and provided us with greater operating flexibility during changing commodity price environments. We have POP arrangements with each of our customers on the Bazor Ridge system that generally include a fee-based element for gathering and treating services. After processing, the residue natural gas is sold and delivered into the Destin Pipeline system, an interstate pipeline operated by Destin Pipeline Company, L.L.C., which has connections with a number of other interstate pipeline systems. We sell the NGLs we recover at the truck rack at the tailgate of the Bazor Ridge processing plant to Dufour Petroleum LP, an affiliate of Enbridge, pursuant to a month-to-month contract. The NGLs are sold on a Mt. Belvieu index-based price. Average throughput on the Bazor Ridge plant for the year ended December 31, 2010 was approximately 9.2 MMcf/d from 41 connected wells. Average throughput increased to approximately 13.4 MMcf/d for the year ended December 31, 2011 as a result of the completion of the Winchester lateral, which we describe below, in November 2010 as well as the connection of two new wells in 2011.

Winchester Lateral. In 2010, we built a new eight-inch diameter pipeline consisting of approximately nine miles of pipe, called the Winchester lateral, to serve the natural gas wells located in Wayne County, Mississippi owned by Venture Oil & Gas, Inc., (Venture), and other producers. The Winchester lateral allowed us to increase the effective throughput capacity of the Bazor Ridge gathering system by approximately 200% to approximately 25 MMcf/d. In conjunction with the construction of the Winchester lateral, we negotiated a five-year acreage dedication from Venture.

The natural gas supply for our Bazor Ridge system is derived primarily from rich associated natural gas produced from oil wells targeting the mature Upper Smackover formation. Production from the wells drilled in this area is generally stable with relatively modest decline rates. An average of one well per year was connected to our Bazor Ridge gathering system over the last three years, with 2 wells connected during the year ended December 31, 2011 and no wells connected during the year ended December 31, 2010. Despite the low number of new wells connected, the generally stable production and relatively modest decline rates from this formation allow us to maintain steady throughput on our Bazor Ridge system. Given the recent and current commodity price environment for crude oil, we expect increasing drilling activity and resulting production in this area during 2012.

Quivira System

The Quivira gathering system consists of approximately 34 miles of pipeline, with a 12-inch diameter mainline and several laterals ranging in diameter from six to eight inches. The system originates offshore of Iberia and St. Mary Parishes of Louisiana in Eugene Island Block 24 and terminates onshore in St. Mary Parish, Louisiana at a connection with the Burns Point Plant, a cryogenic processing plant with a design capacity of 165 MMcf/d that is jointly owned by us and its operator, Enterprise. The Quivira system has a design capacity of approximately 140 MMcf/d. This system also includes an onshore condensate handling facility at Bayou Sale, Louisiana that is upstream of the Burns Point Plant. Residue natural gas is sold into TGP or the Gulf South Pipeline system, an interstate pipeline owned by Boardwalk Pipeline Partners, LP.

The Quivira system is fully subscribed under a firm transportation arrangement through 2012, although a substantial proportion of the revenue is derived from volumetric and fee-based charges. Existing production in our gathering area above our current system capacity is transported on other systems that we believe offer producers less attractive economic alternatives to our customers. Average throughput on the Quivira system for the year ended December 31, 2010 was approximately 77.4 MMcf/d from 16 connected wells. Average throughput increased to approximately 110.8 MMcf/d for the year ended December 31, 2011 as a result of additional production added to the system from a new interconnect to a gathering system owned and operated by Contango Oil & Gas Company.

The Quivira system provides gathering services for natural gas wells and associated natural gas produced from crude oil wells operated by major and independent producers targeting multiple conventional production zones in the shallow waters of the Gulf of Mexico. Wells in this area have historically exhibited relatively low rates of decline throughout the life of the wells. The natural gas produced from these wells is typically natural gas with condensate. An average of two wells per year were connected to the Quivira system over the last three years, with one well connected during the year ended December 31, 2011. Producers generally bear the cost of connecting their wells to our Quivira system.

Burns Point Plant

On December 1, 2011, we acquired a 50% undivided interest in the Burns Point Plant from Marathon Oil Company. The remaining 50% undivided interest is owned by the plant operator, Enterprise. The plant, which is an unincorporated venture, is governed by a construction and operating agreement.

The plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. Our Quivira system currently supplies approximately 85% of the inlet volume to the plant. The residue gas is transported, via pipeline to Gulf South and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC (Promix), an Enterprise operated fractionator. The Burns Point plant is designed to process up to 200 MMcf/d but is currently limited to 165 MMcf/d due to compression constraints. The acquisition complemented our existing assets given the location of the Plant in comparison to the Quivira system.

In 2011 during the period of our ownership, the average throughput at Burns Point was 130.4 MMcf/d and the average NGLs for our account was 11.3 Mgal/d.

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

Offshore Texas System

The Offshore Texas system consists of the GIGS and Brazos systems, two parallel gathering systems that share common geography and operating characteristics. The Offshore Texas system provides gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico region offshore Texas.

The Offshore Texas system consists of approximately 56 miles of pipeline with diameters ranging from six to 16 inches and a design capacity of approximately 100 MMcf/d. Additionally, the Offshore Texas system has two onshore separation and dehydration units, each with a capacity of approximately 40 MMcf/d, that remove water and other impurities from the gathered natural gas before delivering it to our customers. The GIGS system originates offshore of Brazoria County, Texas in Galveston Island Block 343 and connects onshore to the Houston Pipeline system, an intrastate pipeline owned by Energy Transfer Partners, L.P. The Brazos system originates offshore of Brazoria County, Texas in Brazos Block 366 and connects onshore to the Dow Pipeline system, an intrastate pipeline owned by Dow Chemical Company. Substantially all of the natural gas gathered on the Brazos system is delivered to Dow Chemical for use in its chemical plant located in Freeport, Texas pursuant to a month-to-month contract. Dow consumes significantly more natural gas than is provided by the Brazos system and we believe Dow may purchase additional volumes from the Brazos system.

Average throughput on the Offshore Texas system for the year ended December 31, 2010 was 15.3 MMcf/d from approximately 22 connected wells. Average throughput increased to approximately 18.2 MMcf/d for the year ended December 31, 2011 as a result of recent recompletion activity on wells connected to the system.

All of the wells in this area are natural gas wells producing from the Gulf of Mexico shelf offshore Texas. An average of two wells per year were connected to the Offshore Texas system over the last three years, with one well connected during the year ended December 31, 2011. Producers generally bear the cost of connecting their wells to our Texas Offshore system.

Other Gathering and Processing Assets

Alabama Processing. The Alabama Processing system consists of two small skid-mounted treating and processing plants that we refer to, individually, as Atmore and Wildfork. These treating and processing plants are located in Escambia and Monroe Counties of Alabama, respectively, and have design capacities of 3 MMcf/d and 7 MMcf/d, respectively. The Atmore and Wildfork plants processed an average of 1.3 MMcf/d and 0.2 MMcf/d of natural gas, respectively, during the year ended December 31, 2011 and an average of 0.4 MMcf/d and 0.3 MMcf/d, respectively, during the year ended December 31, 2010.

Magnolia System. The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coalbed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transco Pipeline system, an interstate pipeline owned by The Williams Companies, Inc. The Magnolia system consists of approximately 116 miles of pipeline with small-diameter gathering lines and trunklines ranging from six to 24 inches in diameter and one compressor station with 3,328 horsepower. The Magnolia system has a design capacity of approximately 120 MMcf/d. Average throughput on the Magnolia system for the years ended December 31, 2011 and 2010 was approximately 16.9 MMcf/d and 17.4 MMcf/d, respectively. The Magnolia system is also strategically located in the Floyd shale formation, a currently underdeveloped play that may have significant production potential in a higher natural gas price environment.

Our other gathering and processing systems include the Fayette and Heidelberg gathering systems, located in Fayette County, Alabama and Jasper County, Mississippi, respectively. The design capacities for these systems are approximately 5 MMcf/d and approximately 18 MMcf/d, respectively. Average throughput for these systems was approximately 0.5 MMcf/d and approximately 5.3 MMcf/d, respectively, during the year ended December 31, 2011, and approximately 0.5 MMcf/d and approximately 6.5 MMcf/d, respectively, during the year ended December 31, 2010. We also own a small Joule Thompson processing skid, called Stringer, which we lease to a producer in Wayne County, Mississippi.

Growth Opportunities

In our Gathering and Processing segment, we continually seek new sources of raw natural gas supply to increase the throughput volume on our gathering systems and through our processing plants. In addition, we seek to identify and evaluate economically attractive organic expansion and asset acquisition opportunities that leverage our existing asset footprint and strategic relationships with our customers. We also plan to opportunistically pursue strategic and accretive acquisitions within the midstream energy industry that are complementary to our existing asset base or that provide attractive potential returns in new operating regions or business lines. We are evaluating the following growth opportunities:

- the construction of new pipelines and the addition of incremental compression to the Gloria system to accommodate potential new production from our current customers and to extend our asset footprint to reach new areas with existing production;
- the re-commissioning of our stranded Montegut lateral with the potential construction of new pipeline interconnects and new pipeline laterals to provide access to areas of existing production that we do not currently serve, potential access to a third-party processing plant, and takeaway capacity for new production areas;
- the construction of a new pipeline and treating facility on the Bazor Ridge gathering system to accommodate new drilling activity;
- the optimization of the Burns Point processing plant to improve operating efficiencies, enhance NGL recoveries, and increase plant throughput; and
- the development of new gathering systems and processing plants in areas not currently served by our assets.

Customers

Substantially all of the natural gas produced on our Lafitte system is sold to ConocoPhillips for use at its Alliance Refinery in Plaquemines Parish, Louisiana under a contract that expires in 2023. On our Bazor Ridge system, we have a POP arrangement with Venture Oil & Gas Co. that contains an acreage dedication under a contract that expires in 2015. We have a weighted-average remaining life of approximately two years on our fee-based contracts in this segment. The weighted-average remaining life on our POP contracts in this segment is approximately 4 years. For the year ended December 31, 2011, our Gathering and Processing segment derived 55%, 16% and 9% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources, respectively, and 18% and 21% of its segment gross margin from arrangements with Contango Operators Inc. and Venture Oil & Gas Co., respectively. For the year ended December 31, 2010, our Gathering and Processing segment derived 34%, 29% and 10% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources, respectively, and 19% and 13% of its segment gross margin from arrangements with Contango Operators Inc. and Venture Oil & Gas Co., respectively.

Transmission Segment

General

Our Transmission segment is comprised of interstate and intrastate pipelines that transport natural gas from interconnection points on other large pipelines to customers such as local distribution companies, or LDCs, electric utilities or direct-served industrial complexes, or to interconnects on other pipelines. Certain of our pipelines are subject to regulation by FERC and by state regulators. In this segment, we generally enter into firm transportation contracts with our shipper customers to transport natural gas sourced from large interstate or intrastate pipelines. Our Transmission segment assets are located in multiple parishes in Louisiana and multiple counties in Mississippi, Alabama and Tennessee.

In our Transmission segment, we contract with customers to provide firm and interruptible transportation services. In addition, we have a fixed-margin arrangement on our MLGT system whereby we purchase and sell the natural gas that we transport.

For our Midla and AlaTenn systems, which are interstate natural gas pipelines, the maximum and minimum rates for services are governed by each individual system s FERC-approved tariff. In some cases, we agree to discount services or in certain cases we enter into negotiated rate agreements that, with FERC approval, can have rates or other terms that are different than those provided for in the FERC tariff. For our Bamagas and MLGT systems, which are intrastate pipelines providing interstate services under the Hinshaw exemption of the Natural Gas Act (NGA), we negotiate service rates with each of our shipper customers.

The table below sets forth certain information regarding the assets, contracts and revenue for each of the major systems comprising our Transmission segment, as of and for the year ended December 31, 2011:

	Tariff Revenue Composition				
	Firm Transportation Contracts				
	Capacity Reservation Charges	Variable Use Charges	Interruptible Transportation Contracts	Percent of Design Capacity Subscribed Under Firm Transportation Contracts	Weighted Average Remaining Contract Life (in years)
Asset					
Bamagas	100%			44%	9
AlaTenn	82%	2%	16%	26%	2
Midla	81%	4%	15%	100%(a)	1
MLGT(b)			100%	15%	<1

(a) Represents volumes subscribed under firm transportation contracts and design capacity on the mainline of our Midla system.
(b) Included fixed margin arrangements

Bamagas System

Our Bamagas system is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama to two power plants owned by Calpine Corporation, or Calpine, in Morgan County, Alabama. The Bamagas system consists of 52 miles of high pressure, 30-inch pipeline with a design capacity of approximately 450 MMcf/d.

Average throughput on the Bamagas system for the years ended December 31, 2011 and 2010 was approximately 163.9 MMcf/d and 151.5 MMcf/d, respectively. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements. Calpine Corporation is the sole customer on the Bamagas system, with two firm transportation contracts providing for a total of 200 MMcf/d of firm transportation capacity. These contracts, which expire in 2020, ensure steady natural gas supply for the Morgan and Decatur Energy Centers in Morgan County, Alabama. These two natural gas-fired power plants were built in 2002 and 2003 and have a combined capacity of 1,502 megawatts. These generating facilities supply the Tennessee Valley Authority (TVA), with electricity under long-term contractual arrangements between Calpine Corporation and the TVA.

AlaTenn System

The AlaTenn system is an interstate natural gas pipeline that interconnects with TGP and travels west to east delivering natural gas to industrial customers in northwestern Alabama, as well as the city gates of Decatur and Huntsville, Alabama. Our AlaTenn system has a design capacity of approximately 200 MMcf/d and is comprised of approximately 295 miles of pipeline with diameters ranging from three to 16 inches and includes two compressor stations with combined capacity of 3,665 horsepower. The AlaTenn system is connected to four receipt and 61 delivery points, including the Tetco Pipeline system, an interstate pipeline owned by Duke Energy Corporation, and the Columbia Gulf Pipeline system, an interstate pipeline owned by NiSource Gas Transmission and Storage. Average throughput on the AlaTenn system for the years ended December 31, 2011 and 2010 was approximately 46.0 MMcf/d and 48.0 MMcf/d, respectively.

Midla System

Our Midla system is an interstate natural gas pipeline with approximately 370 miles of pipeline linking the Monroe Natural Gas Field in Northern Louisiana and interconnections with the Transco Pipeline system and Gulf South Pipeline system to customers near Baton Rouge, Louisiana. Our Midla system also has interconnects to Centerpoint, TGP and Sonat along a high-pressure lateral at the north end of the system, called the T-32 lateral.

Our Midla system is strategically located near the Perryville Hub, which is a major hub for natural gas produced in the Louisiana and broader Gulf Coast region, including natural gas from the Haynesville shale, Barnett shale, Fayetteville shale, Woodford shale and Deep Bossier formations of Northern Louisiana, Central Texas, Northern Arkansas, Eastern Oklahoma and East Texas, respectively. The Midla system is connected to nine receipt and 19 delivery points. Due to the numerous interstate pipeline connections and growing supply and demand dynamics in the surrounding regions, we believe that our location near the Perryville Hub provides us a strategic advantage in securing supplies of natural gas.

Natural gas flows from north to south on the Midla mainline from interconnections with other interstate pipelines to customers and end users. The Midla system consists of the following components:

- the northern portion of the system, including the T-32 lateral;
- the mainline; and
- the southern portion of the system, including interconnections with the MLGT system and other associated laterals.

The northern portion of the system, including the T-32 lateral, consists of approximately four miles of high pressure, 12-inch diameter pipeline. Natural gas on the northern end of the Midla system is delivered to two power plants operated by Entergy by way of the T-32 lateral and the CLECO Sterlington plant by way of the Sterlington lateral. These power plants are peak-load generating facilities that consumed an aggregate average of approximately 26.8 MMcf/d and 23.6MMcf/d of natural gas for the years ended December 31, 2011 and 2010, respectively. The T-32 lateral is fully subscribed, with approximately 296 MMcf/d of firm transportation capacity under contracts with an average remaining term of 0.3 years that automatically renew on a year-to-year basis.

The mainline has a design capacity of approximately 198 MMcf/d and consists of approximately 172 miles of low pressure, 22-inch diameter pipeline with laterals ranging in diameter from two to 16 inches. This section of the Midla system primarily serves small LDCs under firm transportation contracts that automatically renew on a year-to-year basis. Substantially all of these contracts are at the maximum rates allowed under Midla s FERC tariff. Average throughput on the Midla mainline for the years ended December 31, 2011 and 2010 was approximately 44.6 MMcf/d and 61.6 MMcf/d, respectively.

The southern portion of the system, including interconnections with the MLGT system and other associated laterals, consists of approximately two miles of high and low pressure, 12-inch diameter pipeline. This section of the system primarily serves industrial and LDC customers in the Baton Rouge market through contracts with several large marketing companies. In addition, this section includes two small offshore gathering lines, the T-33 lateral in Grand Bay and the T-51 lateral in Eugene Island 28, each of which are approximately five miles in length. Natural gas delivered on the southern end of the system is sold under both firm and interruptible transportation contracts with average remaining terms of two years.

MLGT System

The MLGT system is an intrastate transmission system that sources natural gas from interconnects with the FGT Pipeline system, the Tetco Pipeline system, the Transco Pipeline system and our Midla system to a Baton Rouge, Louisiana refinery owned and operated by ExxonMobil and seven other industrial customers. Our MLGT system has a design capacity of approximately 170 MMcf/d and is comprised of approximately 54 miles of pipeline with diameters ranging from three to 14 inches. The MLGT system is connected to seven receipt and 17 delivery points. Average throughput on the MLGT system for the years ended December 31, 2011 and 2010 was approximately 51.9 MMcf/d and 50.5 MMcf/d, respectively.

Other Systems

Our other transmission systems include the Chalmette system, located in St. Bernard Parish, Louisiana, and the Trigas system, located in three counties in northwestern Alabama. The approximate design capacities for the Chalmette and Trigas systems are 125 MMcf/d and 60 MMcf/d, respectively. The approximate average throughput for these systems was 10.6 MMcf/d and 13.0 MMcf/d, respectively, for the year ended December 31, 2011 and 6.0 MMcf/d and 5.9 MMcf/d, respectively, for the year ended December 31, 2010. Finally, we also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

Growth Opportunities

In our Transmission segment, we continually seek to increase throughput volumes and volumes under firm transportation contracts on our pipelines. We also seek to identify and evaluate economically attractive organic expansion and asset opportunities that leverage our existing asset footprint and strategic relationships with our customers. Through December 31, 2012 we expect to undertake in our forecast period, we are evaluating the following growth opportunities:

- the addition of delivery points to the AlaTenn system, which we believe will improve overall system flexibility and allow us to capitalize on possible incremental natural gas demand from various electric utilities on our system who are either in the process of, or are evaluating, switching fuel sources from coal to natural gas; and

- the addition of LDC and industrial customers on the AlaTenn system who were commercially underserved by Enbridge Energy Partners, LP our (Predecessor).

- the addition of new facilities and pipelines to accommodate incremental volume on our Midla system from the Tuscaloosa Marine Shale;

- the addition of new pipelines and compression to increase the volume of gas delivered to Natchez, Mississippi for new industrial customers that are developing there;

- the addition of a new interstate pipeline interconnect on our AlaTenn system that would enhance AlaTenn s access to low cost natural gas supply for its current and potential new customers, further enhancing AlaTenn s competitive position in the region and ultimately increasing throughput volume on the pipeline.

Customers

In our Transmission segment, we contract with LDCs, electric utilities, or direct-served industrial complexes, or to interconnections on other large pipelines, to provide firm and interruptible transportation services. Among all of our customers in this segment, the weighted-average remaining life of our firm and interruptible transportation contracts are approximately five years and less than one year, respectively. Enbridge Marketing (US) L.P., ExxonMobil and Calpine Corporation are the three largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 22%, 57% and 8%, respectively, of our segment revenue for the year ended December 31, 2011 and approximately 31%, 43% and 10%, respectively, of our segment revenue for the year ended December 31, 2010. In addition, our Transmission segment derived 37% and 38% of its gross margin from arrangements with Calpine Corporation for the years ended December 31, 2011 and 2010, respectively.

Competition

The natural gas gathering, compression, treating and transportation business is very competitive. Our competitors in our Gathering and Processing segment include other midstream companies, producers, intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. Our major competitors in this segment include TGP and Gulf South.

In our Transmission segment, we compete with other pipelines that service regional markets, specifically in our Baton Rouge market. An increase in competition could result from new pipeline installations or expansions by existing pipelines. Competitive factors include the commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues. Our major competitors for this segment are Southern Natural Gas Company and Louisiana Intrastate Gas.

Safety and Maintenance

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA), and the Pipeline Safety Improvement Act of 2002, (PSIA), which was recently reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high consequence areas, such as high population areas. New pipeline safety legislation requiring more stringent spill reporting and disclosure obligations has been introduced in the U.S. Congress and was passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. Similar legislation has been introduced in the current session of Congress, either independently or in conjunction with the reauthorization of the Pipeline Safety Act. In part, as a result of the PG&E gas line explosion in California last year, the Department of Transportation has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the PHMSA s announced intention to strengthen its rules. The PHMSA recently issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. We believe that this rule does not apply to any of our pipelines. While we cannot predict the outcome of other proposed legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending thorough more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. Additionally, legislative and regulatory changes may also result in higher penalties for the violation of federal pipeline safety regulations. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

We regularly inspect our pipelines and third parties assist us in interpreting the results of the inspections.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the US Department of Transportation (DOT) to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. These state oil and gas standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management (PSM) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety, Superfund and PSM.

We and the entities in which we own an interest are also subject to:

- EPA Chemical Accident Prevention Provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials;
- OSHA Process Safety Management Regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive materials; and
- Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938, (NGA). Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation of our interstate pipelines extends to such matters as:

- rates, services, and terms and conditions of service;
- the types of services offered to customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;

- the initiation and discontinuation of services;

- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and

- participation by interstate pipelines in cash management arrangements.

Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

In 2008, FERC issued Order No. 717, a final rule that implements standards of conduct that include three primary rules: (1) the independent functioning rule, which requires transmission function and marketing function employees to operate independently of each other; (2) the no-conduit rule, which prohibits passing transmission function information to marketing function employees; and (3) the transparency rule, which imposes posting requirements to help detect any instances of undue preference. The FERC has since issued three rehearing orders which generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct. A single rehearing request related to elective issues is currently pending before the FERC.

In 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owner of its interests has an actual or potential income tax liability on such income. The policy statement provided that whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its new policy statement. In December 2005, the FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership s rate case. The FERC reaffirmed its income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The tax allowance policy and the December 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The D.C. Circuit denied these appeals in May 2007 in *ExxonMobil Oil Corporation v. FERC* and fully upheld the FERC s new tax allowance policy and the application of that policy in the December 2005 order. In 2007, the D.C. Circuit denied rehearing of its *ExxonMobil* decision. The *ExxonMobil* decision, its applicability and the issue of the inclusion of an income tax allowance have been the subject of extensive litigation before the FERC. Whether a pipeline s owners have actual or potential income tax liability continues to be reviewed by FERC on a case-by-case basis. How the FERC applies *ExxonMobil* and the policy to pipelines owned by publicly traded partnerships could impose limits on a pipeline s ability to include a full income tax allowance in its cost of service.

In April 2008, the FERC issued a Policy Statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and oil pipelines using FERC s Discounted Cash Flow, or DCF , model for setting cost-of-service or recourse rates. The FERC denied rehearing and no petitions for review of the Policy Statement were filed. In the policy statement, FERC concluded, among other matters that MLPs should be included in the proxy group used to determine return on equity for both oil and natural gas pipelines, but the long-term growth component of the DCF model should be limited to fifty percent of long-term gross domestic product. The adjustment to the long-term growth component, and all other things being equal, results in lower returns on equity than would be calculated without the adjustment. However, the actual return on equity for our interstate pipelines will depend on the specific companies included in the proxy group and the specific conditions at the time of the future rate case proceeding. FERC s policy determinations applicable to MLPs are subject to further modification.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce without an exemption under the NGA, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA, and Part 284 of the FERC s regulations. Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates, terms and conditions of some transportation services provided on our Section 311 pipeline systems are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility s statement of operating conditions are also subject to the FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline s FERC-approved statement of operating conditions could result in alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Hinshaw Pipelines

Intrastate natural gas pipelines are defined as pipelines that operate entirely within a single state, and generally are not subject to FERC s jurisdiction under the NGA. Hinshaw pipelines, by definition, also operate within a single state, but can receive gas from outside their state without becoming subject to FERC s NGA jurisdiction. Specifically, Section 1(c) of the NGA exempts from the FERC s NGA jurisdiction those pipelines which transport gas in interstate commerce if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under the FERC s regulations.

Historically, FERC did not require intrastate and Hinshaw pipelines to meet the same rigorous transactional reporting guidelines as interstate pipelines. However, as discussed below, last year the FERC issued a new rule, Order No. 735, which increases FERC regulation of certain intrastate and Hinshaw pipelines. See Market Behavior Rules; Posting and Reporting Requirements.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. However, some of our natural gas gathering activity is subject to Internet posting requirements imposed by FERC as a result of FERC s market transparency initiatives. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our system due to these regulations.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, (EPAct 2005). Among other matters, the EPAct 2005 amended the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a nexus to jurisdictional transactions. The EPAct 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

The EPAct of 2005 also added a section 23 to the NGA authorizing the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting. In June 2010, the FERC issued the last of its three orders on rehearing further clarifying its requirements.

In 2008, the FERC issued Order No. 720 which increases the Internet posting obligations of interstate pipelines, and also requires major non-interstate pipelines (defined as pipelines that are not natural gas companies under the NGA that deliver more than 50 million MMBtu annually) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu per day or greater. Numerous parties requested modification or reconsideration of this rule. An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Two parties have filed appeals of Order Nos. 720 and 720-A to the Fifth Circuit. The parties have filed briefs but no decision has been issued.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC s website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission s periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 became effective on April 1, 2011. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and Hinshaw pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract.

In July 2010, for the first time the FERC issued an order finding that the prohibition against buy/sell arrangements applies to interstate open access services provided by Section 311 and Hinshaw pipelines. The FERC denied numerous requests for rehearing and motions for late interventions that were filed in response to the July order. However, in October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not yet issued an order.

Offshore Natural Gas Pipelines

Our offshore natural gas gathering pipelines are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide open and nondiscriminatory access to shippers. From 1982 until 2010, the Minerals Management Service (MMS), of the U.S. Department of the Interior (DOI), was the federal agency that managed the nation s oil, natural gas, and other mineral resources on the outer continental shelf, which is all submerged lands lying seaward of state coastal waters which are under U.S. jurisdiction, and collected, accounted for, and disbursed revenues from federal offshore mineral leases. On June 18, 2010, the Minerals Management Service was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). The BOEMRE currently regulates offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the outer continental shelf, and removal of facilities. On January 19, 2011, the U.S. Department of the Interior announced the structures and responsibilities of the two remaining agencies, with the reorganization of BOEMRE into these agencies to be completed by October 1, 2011. Once the reorganization is complete, the BOEMRE will cease to exist. At this time, we cannot predict the impact that this reorganization, or future regulations or enforcement actions taken by the new agencies, may have on our operations.

Sales of Natural Gas and NGLs

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the NGA, the NGPA, and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (CFTC), and the Federal Trade Commission, or FTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Sales of NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

As discussed above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas pipelines and those initiatives may also affect the intrastate transportation of natural gas both directly and indirectly.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for the gathering, compressing, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;

- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;

- delaying system modification or upgrades during permit reviews;

- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and

- enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat and transport natural gas. We cannot assure, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or the Superfund law), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act (RCRA), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate little hazardous waste; however, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and, therefore, be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease, and our Predecessor has in the past owned or leased, properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Oil Pollution Act

In January of 1974, the EPA adopted regulations under the Oil Pollution Act (OPA). These oil pollution prevention regulations require the preparation of a Spill Prevention Control and Countermeasure Plan (SPCC) for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility s operations comply with the requirements. To be in compliance, the facility s SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. We believe that our facilities will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. Other than as described below with respect to our Bazor Ridge plant, we believe that we are in substantial compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Our Bazor Ridge processing plant processes natural gas that is high in hydrogen sulfide, or H_2S. This plant has a Title V Air Permit, which is a permit issued pursuant to Title V of the federal Clean Air Act for larger sources of air emissions. In Mississippi, where the Bazor Ridge plant is located, the Title V program is administered by the Mississippi Department of Environmental Quality (MDEQ). Under this permit, we are allowed to emit up to a specified level of sulfur dioxide, or SO_2, per year.

In the course of preparing our annual MDEQ filing for 2010 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 discovered that SO_2 emission levels during 2009 may have exceeded the threshold that triggers the need for a Prevention of Significant Deterioration (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 (EPCRA), requiring notification of various governmental authorities. We did not make any such EPCRA notifications. In 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 we cannot presently predict the outcome of any enforcement proceedings, any monetary sanctions, operational limitations or restrictions or additional permitting requirements could, either individually or in the aggregate, be materially adverse to us.

We are currently evaluating SO_2 emissions at the Bazor Ridge plant prior to our November 2009 acquisition of the plant. Based on our preliminary analysis, we have recently determined that such SO_2 emissions may have exceeded permitted levels during at least some portion of the statutory five-year limitations period under the federal Clean Air Act, which exceedances may have been significant. We have not yet determined whether the prior owner may have been required to obtain a PSD permit or report SO_2 emissions under EPCRA.

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 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 it for any losses (as defined in the purchase agreement) that may result.

Water Discharges

The Federal Water Pollution Control Act (Clean Water Act), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flow.

Safe Drinking Water Act

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We own and operate an acid gas disposal well in Wayne County, Mississippi as part of our Bazor Ridge gas treating facilities. This well takes a combination of hydrogen sulfide and carbon dioxide recovered from the raw field natural gas feeding the Bazor Ridge Gas plant and injects it into an underground formation permitted for this purpose. The well received an Underground Injection Control (UIC) Class 2 permit through the Mississippi state oil and gas board in 1999. As part of our permit requirements, we perform regular inspection, maintenance and reporting to the state on the condition and operations of this well which is adjacent to our processing plant. We believe that our facilities will not be materially adversely affected by such requirements.

Endangered Species

The Endangered Species Act (ESA), restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

National Environmental Policy Act

The National Environmental Policy Act (NEPA), establishes a national environmental policy and goals for the protection, maintenance, and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews which may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHG) and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. The United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, became effective on February 16, 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent compared to 2005 levels. We continue to monitor the international efforts to address climate change. Their effect on our operations cannot be determined with any certainty at this time.

In the U.S., legislative and regulatory initiatives are underway to limit GHG emissions. The U.S. Congress has considered legislation that would control GHG emissions through a cap and trade program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act (CAA), definition of an air pollutant, and in response the EPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. In 2010, the EPA issued a final rule, known as the Tailoring Rule, that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act.

In addition, on September 2009, the EPA issued a final rule requiring the reporting of GHGs from specified large GHG emission sources in the U.S. beginning in 2011 for emissions in 2010. Our Bazor Ridge facility is currently required to and has reported under this rule in 2011. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. Three of our onshore compression facilities will likely be required to report under this rule, with the first report due to the EPA on March 31, 2012.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase our litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security (DHS), to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. Three of our facilities have more than the threshold quantity of listed chemicals; therefore, a Top Screen evaluation was submitted to the DHS. The DHS reviewed this information and made the determination that none of the facilities are considered high-risk chemical facilities.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remaining land on which our plant sites and major facilities are located, are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. Our Predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Employees

We do not have any employees. The officers of our general partner manage our operations and activities. As of December 31, 2011, our general partner employed approximately 85 people who provide direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by our general partner. None of these employees are covered by collective bargaining agreements, and our general partner considers its employee relations to be good.

Item 1A. Risk Factors

Limited partner units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in our IPO offering document in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

Risks Related to our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution of $0.4125 per unit. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather, process and transport;
- the level of production of oil and natural gas and the resultant market prices of oil and natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- capacity charges and volumetric fees associated with our transportation services;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating, maintenance and general and administrative costs; and
- regulatory action affecting the supply of, or demand for, natural gas, the transportation rates we can charge on our regulated pipelines, how we contract for services, our existing contracts, our operating costs or our operating flexibility.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level of capital expenditures we make;
- the cost of acquisitions, if any;

- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

Because of the natural decline in production from existing wells in our areas of operation, our success depends on our ability to obtain new sources of natural gas, which is dependent on factors beyond our control. Any decrease in the volumes of natural gas that we gather, process or transport could adversely affect our business and operating results.

The natural gas volumes that support our business are dependent on the level of production from natural gas and oil wells connected to our systems, the production of which will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for volumes from successful new wells.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected oil and natural gas and NGL prices;
- demand for oil, natural gas and NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits; and
- the availability of drilling rigs and other production and development costs.

Fluctuations in energy prices can also greatly affect the development of new oil and natural gas reserves. Further declines in natural gas prices could have a negative impact on exploration, development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets.

Because of these and other factors, even if new natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

Natural gas, NGL and other commodity prices are volatile, and a reduction in these prices in absolute terms, or an adverse change in the prices of natural gas and NGLs relative to one another, could adversely affect our gross margin and cash flow and our ability to make distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. The NYMEX daily settlement price for natural gas for the forward month contract in 2011 ranged from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu. Natural gas prices reached relatively high levels in 2005 and early 2006 and have exhibited significant volatility since then, including a sustained decline beginning in 2008, with the forward month gas futures contracts closing at a seven-year low of $2.32 per MMBtu in January 2012. NGL prices are generally positively correlated to the price of WTI crude oil, which has also exhibited frequent and substantial fluctuations. The NYMEX daily settlement price for WTI crude oil for the forward month contract in 2011 ranged from a high of $113.93 per Bbl to a low of $75.67 per Bbl. Crude oil prices reached historically high levels in July 2008, hitting a peak of $145.29 per Bbl, and have demonstrated substantial volatility since then, with the forward month crude oil futures contracts ranging from $33.87 per Bbl in December 2008 to above $113.93 per Bbl in April 2011.

The markets for and prices of natural gas, NGLs and other hydrocarbon commodities depend on factors that are beyond our control. These factors include the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- worldwide economic conditions;

worldwide political events, including actions taken by foreign oil and gas producing nations;

worldwide weather events and conditions, including natural disasters and seasonal changes;

the levels of domestic production and consumer demand;

the availability of imported liquefied natural gas, or LNG;

the availability of transportation systems with adequate capacity;

the volatility and uncertainty of regional pricing differentials;

the price and availability of alternative fuels;

the effect of energy conservation measures;

the nature and extent of governmental regulation and taxation; and

the anticipated future prices of oil, natural gas, NGLs and other commodities.

In our Gathering and Processing segment, we have exposure to direct commodity price risk under percent-of-proceeds processing contracts as well as under our elective processing arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers and retain an agreed percentage of the proceeds (in cash or in-kind) from the sale at market prices of pipeline-quality natural gas and NGLs resulting from our processing activities. We also purchase natural gas at various receipt points, process the gas at a third-party owned natural gas processing facility and sell our portion of the residue gas and NGLs. Under percent-of-proceeds arrangements, our revenue and our cash flows increase or decrease as the prices of natural gas and NGLs fluctuate. When we process natural gas that we purchase for our own account, the relationship between natural gas prices and NGL prices also affects our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process the natural gas that we purchase and process for our own account. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and because of the increased cost (principally that of natural gas shrink that occurs during processing and use of natural gas as a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed pursuant to our elective processing arrangements. For the years ended December 31, 2011 and 2010, percent-of-proceeds arrangements accounted for approximately 41.3% and 34.6%, respectively, of our gross margin, or 58.8% and 53.7%, respectively, of the segment gross margin in our Gathering and Processing segment.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business. Various factors impact the demand for natural gas, NGLs and condensate, including general economic conditions, extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of natural gas processing and transportation capacity and government regulations affecting prices and production levels of natural gas, NGLs and condensate.

Our hedging activities may not be effective in reducing our direct exposure to commodity price risk and the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows.

We have entered into derivative transactions related to only a portion of the equity volumes of NGLs to which we take title. As a result, we will continue to have direct commodity price risk to the unhedged portion of our NGL equity volumes. We currently have no hedges in place beyond December 2012. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity. The derivative instruments we utilize for these hedges are based on posted market prices, which may be lower than the actual NGL prices that we realize in our operations. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. We do not enter into derivative transactions with respect to the volumes of natural gas or condensate that we purchase and sell.

We may not successfully balance our purchases and sales of natural gas, which would increase our exposure to commodity price risks.

We purchase from producers and other suppliers a substantial amount of the natural gas that flows through our pipelines and processing facilities for sale to third parties, including natural gas marketers and other purchasers. We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to percent-of-proceeds arrangements as well as through volumes sold pursuant to our fixed-margin contracts.

In order to mitigate our direct commodity price exposure, we do not enter into natural gas hedge contracts, but rather attempt to balance our natural gas sales with our natural gas purchases on an aggregate basis across all of our systems. We may not be successful in balancing our purchases and sales, and as such may become exposed to fluctuations in the price of natural gas. For example, we are currently net purchasers of natural gas on certain of our systems and net sellers of natural gas on certain of our other systems. Our overall net position with respect to natural gas can change over time and our exposure to fluctuations in natural gas prices could materially increase, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

Although we enter into back-to-back purchases and sales of natural gas in our fixed-margin contracts in which we purchase natural gas from producers or suppliers at receipt points on our systems and simultaneously sell an identical volume of natural gas at delivery points on our systems, we may still be exposed to commodity price risks. For example, the volumes or timing of our purchases and sales may not correspond. In addition, a producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to become unbalanced. If our purchases and sales are unbalanced, we will face increased exposure to commodity price risks, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

We are a relatively small enterprise, and our management has limited history with our assets and limited experience in managing our business as a publicly traded partnership. As a result, operational, financial and other events in the ordinary course of business could disproportionately affect us, and our ability to grow our business could be significantly limited.

We will be smaller than many of the other companies in our industry for the foreseeable future, not only in terms of market capitalization but also in terms of managerial, operational and financial resources. Consequently, an operational incident, customer loss or other event that would not significantly impact the business and operations of the larger companies in our industry may have a material adverse impact on our business and results of operations. In addition, our executive management team is relatively small with limited experience in managing our business as a publicly traded partnership and has managed our business and assets for less than three years. As a result, we may not be able to anticipate or respond to material changes or other events in our business as effectively as if our executive management team had such experience and had managed our business and assets for many years. Furthermore, acquisitions and other growth projects may place a significant strain on our management resources. As a result, our ability to execute our growth strategy and to integrate acquisitions and expansion projects successfully into our existing operations could be significantly limited.

We currently have a limited accounting staff, and if we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results timely and accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended (Exchange Act). Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 requires us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 for our fiscal year ending December 31, 2012. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations.

Prior to our initial public offering, we were a private company and were not required to file reports with the SEC. We currently have limited accounting personnel, and while we have begun the process of evaluating the adequacy of our accounting personnel staffing level and other matters related to our internal controls over financial reporting, we cannot predict the outcome of our review at this time.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, in addition to our limited accounting personnel and management resources, we can provide no assurance as to our, or our independent registered public accounting firm s, future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Any failure to implement and maintain effective internal controls over financial reporting will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

We depend on a relatively small number of customers for a significant portion of our gross margin. The loss of any one or more of these customers could adversely affect our ability to make distributions to you.

A significant percentage of the gross margin in each of our segments is attributable to a relatively small number of customers. Additionally, a number of customers upon which our business depends are small companies that may in the future have limited access to capital or that may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better capitalized companies. In our Gathering and Processing segment, Contango Operators Inc. and Venture Oil & Gas Co. accounted for approximately 18% and 21%, respectively, of our segment gross margin for the year ended December 31, 2011 and approximately 19% and 13%, respectively, of our segment gross margin for the year ended December 31, 2010. In our Transmission segment, Calpine Corporation accounted for approximately 37% and 38% of our segment gross margin for the years ended December 31, 2011 and 2010, respectively. Although we have gathering, processing or transmission contracts with each of these customers of varying duration and commercial terms, if one or more of these customers were to default on their contract or if we were unable to renew our contract with one or more of these customers on favorable terms, we may not be able to replace any of these customers in a timely fashion, on favorable terms or at all. In any of these situations, our gross margin and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

Our natural gas gathering and processing and transportation systems connect to other pipelines or facilities, the majority of which, such as the Southern Natural Gas Company, or Sonat, pipeline, the Toca plant, oil gathering lines on Quivira and the Burns Point processing plant, as well as the Destin, Tennessee Gas and Transco pipelines, are owned and operated by third parties. For example, our elective processing arrangements are entirely dependent on the Toca plant for processing services and the Sonat pipeline for natural gas takeaway capacity and are substantially dependent on the Tennessee Gas Pipeline, or TGP, for natural gas supply volumes. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. If any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

Our reliance on our key customers exposes us to their credit risks, and any material nonpayment or nonperformance by our key customers or purchasers could have a material adverse effect on our revenue, gross margin and cash flows.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to which we provide services and sell commodities. Our three largest purchasers of natural gas in our Gathering and Processing segment are ConocoPhillips, Enbridge Marketing (US) L.P., (EMUS), and Dow Hydrocarbons and Resources, which accounted for approximately 55%, 16% and 9%, respectively, of our segment revenue for the year ended December 31, 2011 and approximately 34%, 29% and 10%, respectively, of our segment revenue for the year ended December 31, 2010. Additionally, EMUS, ExxonMobil and Calpine Corporation are the three largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 22%, 57% and 8%, respectively, of our segment revenue for the year ended December 31, 2011 and approximately 31%, 43% and 10%, respectively, of our segment revenue for the year ended December 31, 2010.

Some of our customers may be highly leveraged or under-capitalized and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. In addition, some of our customers, such as Calpine Corporation, which emerged from bankruptcy in 2008, may have a history of bankruptcy or other material financial and liquidity issues. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue, gross margin and cash flows and our ability to make cash distributions to our unitholders.

Our gathering, processing and transportation contracts subject us to renewal risks.

We gather, purchase, process, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with percent-of-proceeds contracts may choose to switch to fee-based gathering and transportation contracts, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenue, gross margin and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with other midstream companies in our areas of operation. In addition, some of our competitors are large companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, compression, treating, processing or transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering, compression, treating, processing or transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Significant portions of our pipeline systems have been in service for several decades and we have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

We purchased our assets from Enbridge in November 2009. Significant portions of the pipeline systems that we purchased have been in service for many decades. In addition, our executive management team was hired shortly before that purchase and, consequently, has a limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the U.S. Department of Transportation (DOT), has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could harm high consequence areas, including high population areas, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

In addition, many states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our non-exempt pipelines, particularly our AlaTenn and Midla pipelines. We currently estimate that we will incur future costs of approximately $0.1 million during 2012 to complete the testing required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT regulations, we could be subject to penalties and fines.

We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from third parties, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our distributions to our unitholders.

If we are unable to make accretive acquisitions from third parties, whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms or (iii) outbid by competitors or for any other reason, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;

an inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team and its limited history with our assets;

the assumption of unknown liabilities;

limitations on rights to indemnity from the seller;

mistaken assumptions about the overall costs of equity or debt;

the diversion of management s and employees attention from other business concerns;

unforeseen difficulties operating in new geographic areas and business lines; and

customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenue may not increase immediately upon the expenditure of funds on a particular project.

For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenue until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize or only materializes over a period materially longer than expected. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases materially, our cash flows could be adversely affected.

We do not intend to obtain independent evaluations of natural gas reserves connected to our gathering and transportation systems on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We do not intend to obtain independent evaluations of natural gas reserves connected to our systems on a regular or ongoing basis. Accordingly, we may not have independent estimates of total reserves dedicated to some or all of our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation systems are less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Recent incidents and their aftermath could lead to additional governmental regulation of the offshore exploration and production industry, which may result in substantial cost increases or delays in offshore drilling as well as our offshore natural gas gathering activities.

In April 2010, a deepwater exploration well located in the Gulf of Mexico, owned and operated by companies unrelated to us, sustained a blowout and subsequent explosion leading to the leaking of hydrocarbons. In response to this event, certain federal agencies and governmental officials ordered additional inspections of deepwater operations in the Gulf of Mexico. On May 28, 2010, a six-month federal moratorium was implemented on all offshore deepwater drilling projects. On October 12, 2010, the Department of the Interior announced it was lifting the deepwater drilling moratorium. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath has led to additional governmental regulation of the offshore exploration and production industry and delays in the issuance of drilling permits, which may result in volume impacts, cost increases or delays in our offshore natural gas gathering activities, which could materially impact our business, financial condition and results of operations. Although none of our offshore gathering systems currently depend on deepwater production, we cannot predict with any certainty what form any additional regulation or limitations would take or what impact they may have on offshore drilling activity in general or the producers to which we provide offshore gathering services.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured, our operations and financial results could be adversely affected.

Our operations are subject to all of the risks and hazards inherent in the gathering, compressing, treating, processing and transportation of natural gas, including:

damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

inadvertent damage from construction, vehicles, farm and utility equipment;

leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;

ruptures, fires and explosions; and

other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

For example, in April 2010, there was a rupture in our Bazor Ridge gathering pipeline which gathers natural gas high in hydrogen sulfide content which resulted in an extended shut-down of a significant portion of that system until the pipeline could be inspected and repaired. The affected portion of the line is the one that gathered the most significant volumes of gas on this system and delivered it to our Bazor Ridge plant, and we were required to curtail a portion of this flow volume until we built a new bypass pipeline, the Winchester Lateral, connecting this production, as well as potential new production, to the Bazor Ridge plant. The affected section of line was fully shut down for approximately 25 days and, until our Winchester Lateral was completed approximately 177 days later, we were able to gather only approximately 70% of pre-rupture flow volume. The Winchester Lateral cost $3.9 million to construct and the repairs to, and testing of the affected sections of pipe cost approximately $0.5 million.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. For example, we do not have any casualty insurance on our underground pipeline systems that would cover damage to the pipelines. Additionally, we do not have business interruption/loss of income insurance that would provide coverage in the event of damage to any of our underground facilities. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities.

Our interstate natural gas pipelines are subject to regulation by the FERC, which could adversely affect our ability to make distributions to our unitholders.

Our AlaTenn and Midla interstate natural gas transportation systems are subject to regulation by the Federal Energy Regulatory Commission (FERC), under the Natural Gas Act of 1938 (NGA). Under the NGA, the rates for and terms of conditions of service on these interstate facilities must be just and reasonable and not unduly discriminatory. The rates and terms and conditions for our interstate pipeline services are set forth in tariffs that must be filed with and approved by the FERC. Pursuant to the FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

Under the NGA, the FERC has the authority to regulate companies that provide natural gas pipeline transportation services in interstate commerce. The FERC s authority over such companies includes such matters as:

rates and terms and conditions of service;

the types of services interstate pipelines may offer to their customers;

the certification and construction of new facilities;

the acquisition, extension, disposition or abandonment of facilities;

the maintenance of accounts and records;

- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to the amended NGA, the FERC established rules prohibiting energy market manipulation. Also, the FERC s rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation employees function independently of marketing employees. The FERC also requires interstate pipelines to adhere to its rules regarding the filing and approval of transportation agreements that include provisions which differ from the transportation agreements included in their FERC gas tariff. We are conducting a review of the transportation agreements entered into by our predecessor to determine whether, and to what extent, any of our transportation agreements include such provisions. We are subject to audit by the FERC of our compliance in general, including adherence to all its rules and regulations. A violation of these rules, or any other rules, regulations or orders issued or administered by the FERC, may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 (NGPA), to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

Additionally, existing rates may not reflect our current costs of operations, which may have risen since the last time our rates were approved by the FERC. Because proposed rate increases are procedurally complicated, we may have a significant period of time during which our gross margin from such FERC-regulated systems may be materially less than we have historically obtained.

The application of certain FERC policy statements could affect the rate of return on our equity we are allowed to recover through rates and the amount of any allowance (if any) our interstate systems can include for income taxes in establishing their rates for service, which would in turn impact our revenue and/or equity earnings.

In setting authorized rates of return for interstate natural gas pipelines, the FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC allows master limited partnerships (MLPs), to be included in the proxy group to determine return on equity. However, as to such MLPs, the FERC will generally adjust the long-term growth rate used to calculate the equity cost of capital. The FERC stated that the long-term growth projection for natural gas pipeline MLPs will be equal to fifty percent of gross domestic product (GDP), as compared to the unadjusted GDP used for corporations. Therefore, to the extent that MLPs are included in a proxy group, the FERC s policy lowers the return on equity that might otherwise be allowed if there were no adjustment to the MLP growth projection used for the discounted cash flow model. This could lower the return on equity that we would otherwise be able to obtain.

The FERC currently allows partnerships, including MLPs, to include in their cost-of-service an income tax allowance if the partnership s owners have actual or potential income tax liability, a matter that will be reviewed by the FERC on a case-by-case basis. Any changes to the FERC s treatment of income tax allowances in cost-of-service rates or an adverse determination with respect to the inclusion of an income tax allowance in our interstate pipelines rates could result in an adjustment in a future rate case of our interstate pipelines respective equity rates of return that underlie their recourse rates and may cause their recourse rates to be set at a level that is different, and in some instances lower, than the level otherwise in effect.

A change in the jurisdictional characterization or regulation of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows.

Intrastate transportation facilities that do not provide interstate transmission services are exempt from the jurisdiction of the FERC under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that our intrastate natural gas pipelines and related facilities that are not engaged in providing interstate transmission services are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to FERC jurisdiction. We believe that our natural gas gathering pipelines meet the traditional tests that the FERC has used to determine if a pipeline is a gathering pipeline and is therefore not subject to the FERC s jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, the FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and intrastate transportation and gathering facilities, on the other, is a fact-based determination made by the FERC on a case by case basis. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

Moreover, FERC regulation affects our gathering, transportation and compression business generally. The FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, capacity release and market transparency and market center promotion, directly and indirectly affect our gathering business. In addition, the classification and regulation of our gathering and intrastate transportation facilities also are subject to change based on future determinations by the FERC, the courts or Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, the FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of these companies transferring gathering facilities to federally unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, compression, treating and transportation operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;

- the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or the Superfund law), and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;

- the federal Water Pollution Control Act (Clean Water Act), and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;

- the federal Oil Pollution Act (OPA), and analogous state laws that establish strict liability for releases of oil into waters of the United States;

- the federal Resource Conservation and Recovery Act (RCRA), and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;

- the Endangered Species Act (ESA); and

- the Toxic Substances Control Act (TSCA), and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency (EPA), and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. For example, with respect to our Bazor Ridge processing plant, we determined that (i) emissions during 2009 and 2010 exceeded the sulfur dioxide, or SO_2, 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 (PSD), permit in 2009 under the federal Clean Air Act, and (iii) our SO_2 emission levels required reporting under the federal Emergency Planning and Community Right-to-Know Act (EPCRA), in 2009 and 2010 that was not made. As a result of 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, the consequences of which (either individually or in the aggregate) could be material. Please read Business Environmental Matters Air Emissions for more information about these matters. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance. Please read Business Environmental Matters for more information.

Our operations may impact the environment or cause environmental contamination, which could result in material liabilities to us.

Our operations use hazardous materials, generate limited quantities of hazardous wastes and may affect runoff or drainage water. In the event of environmental contamination or a release of hazardous materials, we could become subject to claims for toxic torts, natural resource damages and other damages and for the investigation and cleanup of soil, surface water, groundwater, and other media. Such claims may arise out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share. These and other impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could have a material adverse effect on us. Please read Business Environmental Matters.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the natural gas services we provide.

In recent years, the U.S. Congress has been considering legislation to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane, which are understood to contribute to global warming. The American Clean Energy and Security Act of 2009, passed by the House of Representatives, would, if enacted by the full Congress, have required greenhouse gas (GHG), emissions reductions by covered sources of as much as 17% from 2005 levels by 2020 and by as much as 83% by 2050. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that smaller sources such as our gas-fired compressors could become subject to GHG-related regulation. Depending on the particular program, we could be required to control emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing Clean Air Act authority. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. Our Bazor Ridge facility is currently required to report under this rule beginning in 2011. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. Three of our onshore compression facilities will likely be required to report under this rule, with the first report due to the EPA on March 31, 2012. In 2010, the EPA also issued a final rule, known as the Tailoring Rule, that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act.

In July 2011, the EPA proposed rules that would establish new air emission controls for natural gas processing operations. Specifically, the EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs), and a separate set of emission standards to address hazardous air pollutants frequently associated with natural gas processing activities. The proposed rules would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them during the first quarter of 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new leak detection and related equipment.

Several of the EPA s greenhouse gas rules are being challenged in pending court proceedings and, depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas we gather, treat or otherwise handle in connection with our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas, resulting in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Our pipelines may become subject to more stringent safety regulation.

Proposed pipeline safety legislation requiring more stringent spill reporting and disclosure obligations was introduced in the U.S. Congress and passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. Similar legislation has been proposed in the current session of Congress, either independently or in conjunction with the reauthorization of the Pipeline Safety Act. The Department of Transportation (DOT), has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the Pipeline and Hazardous Materials Safety Administration s announced intention to strengthen its rules. The Pipeline and Hazardous Materials Safety Administration (PHMSA), which is part of DOT, recently issued a final rule, effective October 1, 2011, applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. We believe that this rule does not apply to any of our pipelines. While we cannot predict the outcome of other proposed legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. Additionally, legislative and regulatory changes may also result in higher penalties for the violation of federal pipeline safety regulations. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010 federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted. The Dodd-Frank Act provides new statutory requirements for swap transactions, including oil and gas hedging transactions. These statutory requirements must be implemented through regulation primarily through rules to be adopted by the Commodities Futures Trading Commission (CFTC). The Dodd-Frank Act provisions are intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which most swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. Many market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that may impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants will be subject to new reporting and recordkeeping requirements.

The impact of the Dodd-Frank Act on our hedging activities is uncertain at this time, and the CFTC has not yet promulgated final regulations implementing the key provisions. Although we do not believe we will need to register as a swap dealer or major swap participant, and do not believe we will be subject to the new requirements to trade on an exchange or swap execution facility or to clear swaps through a central counterparty, we may have new regulatory burdens. Moreover, the changes to the swap market as a result of Dodd-Frank implementation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our willingness or ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Restrictions in our new credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our common units.

On August 1, 2011, we entered into a new credit facility. Our new credit facility limits our ability to, among other things:

- incur additional debt;
- make distributions on or redeem or repurchase units;

- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer or otherwise dispose of assets.

Our new credit facility also contains covenants requiring us to maintain certain financial ratios.

The provisions of our credit facility affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to affect any of these actions on satisfactory terms or at all.

As our common units will be yield-oriented securities, increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

We currently have a small management team, and our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

We currently have a small management team, and our ability to operate our business and implement our strategies depends on the continued contributions of certain executive officers and key employees of our general partner. Our general partner has a smaller managerial, operational and financial staff than many of the companies in our industry. Given the small size of our management team, the loss of any one member of our management team could have a material adverse effect on our business. In addition, certain of our field operating managers are approaching retirement age. We believe that our future success will depend on our continued ability to attract and retain highly skilled management personnel with midstream natural gas industry experience and competition for these persons in the midstream natural gas industry is intense. Given our small size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

A shortage of skilled labor in the midstream natural gas industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The gathering, treating, processing and transporting of natural gas requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our general partner s employees, our results of operations could be materially and adversely affected.

Our work force could become unionized in the future, which could adversely affect the stability of our production and materially reduce our profitability.

All of our systems are operated by non-union employees of our general partner. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could adversely affect the stability of our operations and materially reduce our profitability.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber-attacks on our customer and employee data may result in financial loss and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Risks Inherent in an Investment in Us

AIM Midstream Holdings directly owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. AIM Midstream Holdings and our general partner have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of us and our unitholders.

AIM Midstream Holdings owns and controls our general partner and appoints all of the officers and directors of our general partner, some of whom are also officers of AIM Midstream Holdings. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, AIM Midstream Holdings. Conflicts of interest may arise between AIM Midstream Holdings and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of AIM Midstream Holdings over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires AIM Midstream Holdings to pursue a business strategy that favors us;

- our partnership agreement limits the liability of and reduces the fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;

- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;

our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the ability of the subordinated units to convert to common units;

our general partner determines which costs incurred by it are reimbursable by us;

our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;

our partnership agreement permits us to classify up to $11.5 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

our general partner intends to limit its liability regarding our contractual and other obligations;

our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;

our general partner controls the enforcement of the obligations that it and its affiliates owe to us;

our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and

our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

AIM Midstream Holdings is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

AIM Midstream Holdings is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, AIM Midstream Holdings may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while AIM Midstream Holdings may offer us the opportunity to buy additional assets from it, it is under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We are approved to list our common units on the NYSE. Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner s board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE s shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. Please read Management.

If you are not an eligible holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity s owners are U.S. individuals or entities subject to such taxation. If you are not an eligible holder, our general partner may elect not to make distributions or allocate income or loss on your units, and you run the risk of having your units redeemed by us at the lower of your purchase price cost and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our general partner.

C***ommon units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.***

Our partnership agreement gives our general partner the power to amend the agreement to avoid any adverse effect on the maximum applicable rates chargeable to customers by us under FERC regulations, or in order to reverse an adverse determination that has occurred regarding such maximum rate. If our general partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us, then our general partner may adopt such amendments to our partnership agreement as it determines are necessary or advisable to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to continue limiting its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and in our new credit facility, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our general partner s fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner or otherwise, free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith, meaning that it believed that the decision was in, or not opposed to, the best interest of our partnership;

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

a) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights without the approval of the conflicts committee of our general partner s board or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our general partner in connection with resetting the target distribution levels related to our general partner s incentive distribution rights. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner s Right to Reset Incentive Distribution Levels.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner will be chosen by AIM Midstream Holdings. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot currently remove our general partner without its consent.

The unitholders currently are unable to remove our general partner without its consent because our general partner and its affiliates owns sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner AIM Midstream Holdings who owns 57.8% of our outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of AIM Midstream Holdings to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

AIM Midstream Holdings may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

AIM Midstream Holdings currently holds an aggregate of 725,120 common units and 4,526,066 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. AIM Midstream Holdings owns approximately 16.0% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), AIM Midstream Holdings will own approximately 58.0% of our outstanding common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service (IRS), on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate distributions (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on us by Texas, and if applicable by any other state, will reduce the cash available for distribution to you. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Recently, members of the U.S. Congress have considered substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships, which, if enacted, may or may not be applied retroactively. Although we are unable to predict whether any of these changes or any other proposals will ultimately be enacted, any such changes could negatively impact the value of an investment in our common units.

Our unitholders share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder s allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from that income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take, and the IRS s positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale of your common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read Material Federal Income Tax Consequences Disposition of Common Units Recognition of Gain or Loss for a further discussion of the foregoing.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Section 754 Election for a further discussion of the effect of the depreciation and amortization positions we have adopted.

W***e prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.***

We will prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Andrews Kurth LLP has not rendered an opinion with respect to whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations. Please read Material Federal Income Tax Consequences Disposition of Common Units Allocations Between Transferors and Transferees.

A unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We will adopt certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years. Please read Material Federal Income Tax Consequences Disposition of Common Units Constructive Termination for a discussion of the consequences of our termination for federal income tax purposes.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We will initially own property or conduct business in a number of states, most of which currently impose a personal income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

A description of our properties is contained in Item 1. Business of this Annual Report and incorporated into this Item 2. By reference.

Our principal executive offices are located at 1614 15th Street, Suite 300, Denver, CO 80202 and our telephone number is 720-457-6060.

Item 3. 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.

Item 4. Mine Safety Disclosure

Not applicable.

PART II

Item 5. Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common units have been listed on the New York Stock Exchange since July 27, 2011 under the symbol AMID . The following table sets forth the high and low sales prices of the common units, as reported by the New York Stock Exchange (NYSE) for each quarter since our IPO through December 31, 2011:

Quarter Ended	Unit Prices High	Unit Prices Low	Distributions Declared
September 30, 2011	$ 23.37	$ 16.00	$ 0.2690 (1)
December 31, 2011	$ 19.57	$ 16.80	$ 0.4325

(1) The distribution declared for the quarter ended Septempber 30, 2011 was made in respect of the period from August 1, 2011, the date of the consummation of our initial public offering, through that date on a prorated basis.

As of March 14, 2012, there were 10 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 4,526,066 subordinated units and 184,737 general partner units, for which there is no established trading market. All of the suboridinated units and general partner units are held by affiliates of our general partner. Our general partner and its affiliates receive quarterly distributions on these units only after sufficient funds have been paid to the common units.

Overview of Distributions

During the past two fiscal years, our unitholders have received distributions from us on a pro rata basis. Holders of our previously outstanding units received their pro rata share of distributions as follows:

	(in thousands)
May 2010	$ 5,280
August 2010	3,250
November 2010	3,249
February 2011	3,664
May 2011	3,674
August 2011 (a)	33,723
November 2011 (b)	2,485

(a) In August 2011 we made a special distribution of $33.7 million in connection with our IPO to AIM Midstream Holdings, LLC, participants in our LTIP holding common units and our general partner.

(b) Represents a pro-rated distribution of $0.2690 per unit for the period from August 2, 2011 through September 30, 2011.

On January 24, 2012, we announced a fourth quarter distribution of $0.4325 per unit payable on February 10, 2012 to unitholders of record on February 3, 2012.

Our Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects our belief that our unitholders will be better served if we distribute rather than retain our available cash. Generally, our available cash is the sum of our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

The following table sets forth the number of common, subordinated common and general partner units at December 31, 2011:

	December 31, 2011	2010
	(in thousands)	
Limited partner common units	4,561	5,363
Limited partner subordinated units	4,526	
General partner units	185	109

Our general partner s initial 2.0% interest in distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.

The subordination period generally will end and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $1.65 on each outstanding common and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after September 30, 2014. The subordination period will automatically terminate and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $2.475 (150% of the annualized minimum quarterly distribution) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 2.0% interest and incentive distribution rights for any four consecutive quarter period ending on or after September 30, 2012; provided that we have paid at least the minimum quarterly distribution from operating surplus on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each quarter in that four-quarter period.

If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except in some circumstances during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units and the corresponding distributions on our general partner s 2.0% interest, we will use this excess available cash to pay any distribution arrearages on the common units related to prior quarters before any cash distribution is made to holders of the subordinated units.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date.

Securities Authorized for Issuance Under Equity Compensation Plans

Our general partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our general partner adopted an LTIP for its employees, consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our general partner adopted an amended and restated LTIP. The LTIP currently permits the grant of awards that include phantom units that typically vest ratably over four years, covering an aggregate of 303,601 of our units. At December 31, 2011 and 2010, 54,827 and 62,246 units, respectively, were available for future grant under the LTIP giving retroactive treatment to the reverse unit split described in Note 13 Partners Capital in the audited consolidated financial statements included in this Annual Report beginning on page F-1.

Recent Sales of Unregistered Units

None

Repurchase of Equity by American Midstream Partners, LP

None

Item 6. Selected Historical Financial and Operating Data

The following table presents selected historical consolidated financial and operating data for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements, historical combined Predecessor financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those financial statements and notes, which for the years 2011, 2010, the period from our inception on August 20, 2009 to December 31, 2009 and the Predecessor s 10 month period ended October 31, 2009 begin on F-1 to this Annual Report.

We acquired the Predecessor assets effective November 1, 2009. During the period from our inception, on August 20, 2009, to October 31, 2009, we had no operations although we incurred certain fees and expenses of approximately $6.4 million associated with our formation and the acquisition of our assets from Enbridge, which are reflected in the Transaction costs line item of our consolidated financial data for the period from August 20, 2009 through December 31, 2009.

For a detailed discussion of the following table, please read Management s Discussion and Analysis of Financial Condition and Results of Operations.

	American Midstream Partners, LP and Subsidiaries (Successor)			American Midstream Partners Predecessor		
	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to 2009 December 31, 2009	10 Months Ended October 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
	(in thousands, except per unit and operating data)					
Statement of Operations Data:						
Revenue	$ 248,282	$ 212,248	$ 32,833	$ 143,132	$ 366,348	$ 290,777
Realized gain (loss) in early termination of commodity derivatives	(2,998)					
Unrealized gain (loss) on commodity derivatives	(541)	(308)				
Total revenue	244,743	211,940	32,833	143,132	366,348	290,777
Operating expenses:						
Purchases of natural gas, NGLs and condensate	202,403	173,821	26,593	113,227	323,205	251,959
Direct operating expenses	12,856	12,187	1,594	10,331	13,423	15,334
Selling, general and administrative expenses	10,794	7,120	1,196	8,577	8,618	10,294
Advisory services agreement termination fee	2,500					
Transaction expenses	282	303	6,404			
Equity compensation expense(a)	3,357	1,734	150			
Depreciation expense	20,705	20,013	2,978	12,630	13,481	12,500
Total operating expenses	252,897	215,178	38,915	144,765	358,727	290,087
Gain (loss) on acquisition of assets	565					
Gain (loss) on sale of assets, net	399					
Operating income (loss)	(7,190)	(3,238)	(6,082)	(1,633)	7,621	690
Other income (expense)						
Interest expense	(4,508)	(5,406)	(910)	(3,728)	(5,747)	(8,527)
Other income (expense)				24	854	(1,209)
Net income (loss)	(11,698)	(8,644)	(6,992)	$ (5,337)	$ 2,728	$ (9,046)
General partner s interest in net income (loss)	(233)	(173)	(140)			
Limited partners interest in net income (loss)	$ (11,465)	$ (8,471)	$ (6,852)			
Limited partners net income (loss) per unit	$ (1.64)	$ (1.66)	$ (3.13)			
Weighted average number of units used in computation of limited partners net income (loss) per unit	6,997	5,099	2,187			
Statement of Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 10,432	$ 13,791	$ (6,531)	$ 14,589	$ 18,155	$ (447)
Investing activities	(41,744)	(10,268)	(151,976)	(853)	(10,486)	745
Financing activities	32,120	(4,609)	159,656	(14,088)	(7,929)	322
Other Financial Data:						
Adjusted EBITDA(b)	$ 21,041	$ 18,263	$ 3,450	11,021	21,956	11,981
Distributable cash flow(f)	13,212	9,549	1,913			
Distributable cash flow per weighted average unit outstanding(g)	1.85	1.84	0.86			
Gross margin(c)	46,187	38,119	6,240	29,905	43,143	38,818
Segment gross margin:						
Gathering and Processing	32,450	24,595	3,698	20,024	27,354	22,108

Transmission	13,737	13,524	2,542	9,881	15,789	16,710
Balance Sheet Data (At Period End);						
Cash and cash equivalents	$ 871	$ 63	$ 1,149	$ 149	$ 421	$ 681
Accounts receiveable, net and unbilled revenue	20,963	22,850	19,776	8,756	9,532	13,643
Property, plant and equipment, net	170,231	146,808	146,226	205,126	216,903	219,898
Total assets	199,551	173,229	174,470	250,162	277,242	287,290
Total debt (current and long term)(d)	66,270	56,370	61,000		60,000	60,000
Operating Data:						
Gathering and processing Segment:						
Throughput (MMcf/d)	250.9	175.6	169.7	211.8	179.2	
Plant inlet volume (MMcf/d)(e)	36.7	9.9	11.4	11.7	12.5	
Gross NGL production (Mgal/d)(e)	54.5	34.1	38.2	39.3	40.2	
Transmission segment:						
Throughput (MMcf/d)	381.1	350.2	381.3	357.6	336.2	
Firm transportation - capacity reservation (MMcf/d)	702.2	677.6	701.0	613.2	627.3	
Interruptible transportation throughput (MMcf/d)	69.0	80.9	118.0	121.0	141.6	

(a) Represents cash and non-cash costs related to our LTIP. Of these amounts, $1.6 million, $1.2 million and $0.2 million, for the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, respectively, were non-cash expenses.
(b) 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 Selected Historical Financial and Operating Data 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.
(c) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, Note 18 to our audited consolidated financial statements included elsewhere in this Annual Report and for a discussion of how we use gross margin to evaluate our operating performance, please read How We Evaluate Our Operations.
(d) Excludes Predecessor Note payable to Enbridge Midcoast Limited Holdings, L.L.C. of $39.3 million as of December 31, 2008.
(e) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read Business Gathering and Processing Segment Gloria System.
(f) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Selected Historical Financial and Operating Data Non-GAAP Financial Measures, and for a discussion of how we use distributable cash flow to evaluate our operating performance, please read How We Evaluate Our Operations.
(g) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Selected Historical Financial and Operating Data Non-GAAP Financial Measures, and for a discussion of how we use distributable cash flow to evaluate our operating performance, please read How We Evaluate Our Operations.
(h) Includes unvested phantom units with DERs, which are considered participating securities, of 205,864 and 175,236 as of December 31, 2010 and 2009, respectively . The DER s were eliminated on June 9, 2011. There were no such unvested phantom units with DERs at December 31, 2011. The unit count also gives effect to the reverse unit split as described in Note 13, Partners Capital of our audited consolidated financial statements included in this Annual Report beginning on page F-1.

Adjusted EBITDA

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

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

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

We changed our calculation of adjusted EBITDA for 2011 to include the straight-line amortization of commodity put premiums over the life of the associated commodity put contracts. This is necessary as all unrealized commodity gains and losses, by definition, are excluded in calculating adjusted EBITDA and such premium costs would only be included in the calculation of adjusted EBITDA at the expiration of the put contract. We believe this treatment better reflects the allocation of commodity put premium costs over the benefit period of the commodity put contract. Commodity put premium amortization included in the calculation of adjusted EBITDA $0.4 million for the year ended December 31, 2011. Further we made a change to the calculation to exclude construction, operating and maintenance agreement (COMA) income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the year ended December 31, 2011 was $0.9 million.

Distributable Cash Flow

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

We define distributable cash flow as adjusted EBITDA plus interest income, less cash paid for interest expense, normalized integrity management costs and normalized maintenance capital expenditures. The GAAP measure most directly comparable to distributable cash flow is net cash flows from operating activities.

Note About Non-GAAP Financial Measures

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

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

For a reconciliation of gross margin to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 18 to our audited consolidated financial statements included in this Form 10-K.

The following tables reconcile the non-GAAP financial measures, adjusted EBITDA and distributable cash flow used by management to their most directly comparable GAAP measures:

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to	Predecessor Ten Months ended
	2011	2010	December 31, 2009	October 31, 2009
			(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
Add:				
Depreciation expense	20,705	20,013	2,978	12,630
Interest expense	4,508	5,406	910	3,728
Realized loss on early termination of commodity derivatives	2,998			
Realized loss on commodity put purchase costs	308			
Unrealized (gain) loss on commodity derivatives	541			
Non-cash equity compensation expense	1,607	1,185	150	
Advisory services agreement termination fee	2,500			
Special distribution to holders of LTIP phantom units	1,624			
Transaction costs	282	303	6,404	
Deduct:				
Construction, operating and maintenance agreement income (COMA)	879			
Straight-line amortization of put costs (1)	409			
Other post employment benefit plan net periodic benefit (cost)	82			
Gain (loss) on acquisition of assets, net	565			
Gain (loss) on sale of assets, net	399			
Adjusted EBITDA	$ 21,041	$ 18,263	$ 3,450	$ 11,021

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

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to December 31,
	2011	2010	2009
		(in thousands)	
Reconciliation of Distributable Cash to Net Cash Flows from Operating Activities:			
Net cash provided / (used) in operating activities	10,432	13,791	(6,531)
Add:			
Change in operating assets and liabilities	1,247	(45)	2,790
Interest expense	3,246	4,591	792
Advisory services agreement termination fee	2,500		
Realized (gain) loss on early termination of commodity derivatives	2,998		
Special distribution to holders of LTIP phantom units	1,624		

Transaction costs	282	303	6,404
Deduct:			
Cash interest expense (1)	3,246	4,591	792
Straight-line amortization of put costs (2)	409		
COMA income	879		
Integrity management costs (3)	1,500	1,500	250
Maintenance capital expenditures (4)	3,083	3,000	500
Distributable Cash Flow	13,212	9,549	1,913

(1) Excludes amortization of debt issuance costs and mark-to-market adjustments related to interest rate derivatives.
(2) Amounts noted represent the straight-line amortization of the cost of commodity put contracts over the life of the contract.
(3) Amounts noted represent average estimated integrity management costs over the 7 year mandatory testing cycle.
(4) Amounts noted represent estimated annual maintenance capital expenditures of $3.5 million which is what we expect to be required to maintain our assets over the long term.

Item 7. 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 audited consolidated financial statements and the related notes thereto included elsewhere in this Form 10-K. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption Cautionary Statement Regarding Forward-Looking Statements.

Overview

We are a growth-oriented Delaware limited partnership that was formed by affiliates of 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 five intrastate pipelines. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 1,400 miles of pipelines that gather and transport over 500 MMcf/d of natural gas.

Our operations are organized into two segments: (i) Gathering and Processing and (ii) Transmission. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, transporting and treating natural gas. Where we provide processing services at the plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and resulting natural gas liquids (NGLs) under percent-of-proceeds (POP) arrangements. We own and operate three processing facilities that collectively produced an average of approximately 52.6Mgal/d and 34.1 Mgal/d of gross NGLs for years ended December 31, 2011 and 2010, respectively. Effective November 1, 2011, we acquired a 50% undivided non-operating interest in the Burns Point Plant from which we received 11.3 Mgal/d of NGLs to our account. In addition, in connection with our elective processing arrangements, we contract for processing capacity at the Toca plant operated by a subsidiary Enterprise, where we have the option to process natural gas that we purchase. Under these arrangements, we sold an average of approximately 27.4 Mgal/d and 28.1 Mgal/d of net equity NGL volumes for the years ended December 31, 2011 and 2010, 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.

Significant Developments During the Year Ended December 31, 2011

Initial Public Offering

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

Upon closing of our IPO on August 1, 2011, we issued 3,750,000 common units pursuant to the Registration Statement at a price per unit of $21.00. The Registration Statement registered the offer and sale of securities with a maximum aggregate offering price of $90,562,500. The aggregate offering amount of the securities sold pursuant to the Registration Statement was $78,750,000. In our IPO, we granted the underwriters a 30 day option to purchase up to 562,500 additional units to cover over-allotments, if any, on the same terms. This option expired unexercised on August 30, 2011.

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

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

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

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

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

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

New $100 Million Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our $85 million credit facility (old credit facility) evidenced by our credit agreement with a syndicate of lenders, for which Comerica Bank acted as Administrative Agent, and entered into a $100 Million Credit Facility evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto (new credit facility). The new credit facility also provides for a $50 million dollar accordion feature for accretive growth projects. If the accordion feature were to be exercised, the total commitment under the new facility would be $150 million.

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

Acquisition of a 50% non-operating interest in the Burns Point Plant

On December 1, 2011, we acquired a 50% undivided interest in the Burns Point Plant from Marathon Oil Company for total cash consideration of $35.5 million. No liabilities of the Seller were assumed. The purchase was effective November 1, 2011. The remaining 50% undivided interest is owned by the Plant operator, Enterprise Gas Processing, LLC (Operator). The Plant, which is an unincorporated venture, is governed by a construction and operating agreement.

The Burns Point Plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The Plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. Our Quivira system currently supplies approximately 85% of the inlet volume to the plant. The residue gas is transported, via pipeline to Gulf South and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC (Promix), an Enterprise operated fractionator. The current operating capacity of the plant is 165 MMcf/d. The acquisition complemented our existing assets given the location of the Plant in comparison to the Quivira system.

Subsequent Event

On January 24, 2012, we announced a distribution of $0.435 per unit for the fourth quarter 2011, payable on February 10, 2012 to unit holders of record on February 3, 2012.

Our Operations

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

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

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

Gathering and Processing Segment

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

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

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas, we are able to lock in a fixed-margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

Percent-of-Proceeds Arrangements. Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas and NGLs at market prices. Where we provide processing services at the processing plants that we own or obtain processing services for our own account in connection with our elective processing arrangements, such as under our Toca contract, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas, such as for our interest in the Burns Point Plant. Please read Business Gathering and Processing Segment Gloria System.

Interest in the Burns Point Plant

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

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in volumes and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. Under our typical percent-of-proceeds arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our percent-of-proceeds arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. Please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk.

Transmission Segment

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

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

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

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

The gross margin we earn from our transportation activities is directly related to the capacity reservation on, and actual volume of natural gas that flows through, our systems, neither of which is directly dependent on commodity prices. However, a sustained decline in market demand could result in a decline in volumes and, thus, a decrease in our commodity-based gross margin under firm transportation contracts or gross margin under our interruptible transportation and fixed-margin contracts.

Contract Mix

Set forth below is a table summarizing our average contract mix for the years ended December 31, 2011 and 2010:

	For the Year Ended December 31, 2011		For the Years Ended December 31, 2010	
	Segment Gross Margin (in millions)	**Percent of Segment Gross Margin**	**Segment Gross Margin** (in millions)	**Percent of Segment Gross Margin**
Gathering and Processing				
Fee based	$ 9.3	28.6%	$ 6.5	26.4%
Fixed Margin	4.1	12.6%	4.9	19.9%
Percent-of-Proceeds	19.1	58.8%	13.2	53.7%
Total	$ 32.5	100.0%	$ 24.6	100.0%
Transmission				
Firm transportation	$ 10.4	75.9%	$ 10.8	80.0%
Interruptible transportation	2.1	15.3%	2.0	14.8%
Fixed margin	1.2	8.8%	0.7	5.2%
Total	$ 13.7	100.0%	$ 13.5	100.0%

How We Evaluate Our Operations

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

Throughput Volumes

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

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

Gross Margin and Segment Gross Margin

Gross margin and segment gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as revenue generated from gathering and processing operations less the cost of natural gas, NGLs and condensate purchased. Revenue includes revenue generated from fixed fees associated with the gathering and treating of natural gas and from the sale of natural gas, NGLs and condensate resulting from gathering and processing activities under fixed-margin and percent-of-proceeds arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to percent-of-proceeds arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

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

Effective January 1, 2011, we changed our gross margin and segment gross margin measure to exclude unrealized mark-to-market adjustments related to our commodity derivatives. For the year ended December 31, 2011, $0.5 million of unrealized losses was 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 year ended December 31, 2011, $3.0 million in such realized losses was excluded from gross margin and the Gathering and Processing segment gross margin.

Direct Operating Expenses

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

Adjusted EBITDA

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

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

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

We changed our calculation of adjusted EBITDA for 2011 to include the straight-line amortization of commodity put premiums over the life of the associated commodity put contracts. This is necessary as all unrealized commodity gains and losses, by definition, are excluded in calculating adjusted EBITDA and such premium costs would only be included in the calculation of adjusted EBITDA at the expiration of the put contract. We believe this treatment better reflects the allocation of commodity put premium costs over the benefit period of the commodity put contract. Commodity put premium amortization included in the calculation of adjusted EBITDA $0.4 million for the year ended December 31, 2011. Further we made a change to the calculation to exclude construction, operating and maintenance agreement (COMA) income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the year ended December 31, 2011 was $0.9 million.

Distributable Cash Flow

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

We define distributable cash flow as adjusted EBITDA plus interest income, less cash paid for interest expense, normalized integrity management costs and normalized maintenance capital expenditures. The GAAP measure most directly comparable to distributable cash flow is net cash flows from operating activities.

Note About Non-GAAP Financial Measures

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

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

For a reconciliation of gross margin to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 18 to our audited consolidated financial statements included in this Form 10-K.

The following tables reconcile the non-GAAP financial measures, adjusted EBITDA and distributable cash flow used by management to their most directly comparable GAAP measures:

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to	Predecessor
				Ten Months ended
	2011	2010	December 31, 2009	October 31, 2009
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
Add:				
Depreciation expense	20,705	20,013	2,978	12,630
Interest expense	4,508	5,406	910	3,728
Realized loss on early termination of commodity derivatives	2,998			
Realized loss on commodity put purchase costs	308			
Unrealized (gain) loss on commodity derivatives	541			
Non-cash equity compensation expense	1,607	1,185	150	
Advisory services agreement termination fee	2,500			
Special distribution to holders of LTIP phantom units	1,624			
Transaction costs	282	303	6,404	
Deduct:				
Construction, operating and maintenance agreement income (COMA)	879			
Straight-line amortization of put costs (1)	409			
Other post retirement plan net periodic benefit (cost)	82			
Gain (loss) on acquisition of assets, net	565			
Gain (loss) on sale of assets, net	399			
Adjusted EBITDA	$ 21,041	$ 18,263	$ 3,450	$ 11,021

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

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to December 31,
	2011	2010	2009
	(in thousands)		
Reconciliation of Distributable Cash to Net Cash Flows from Operating Activities:			
Net cash provided / (used) in operating activities	10,432	13,791	(6,531)
Add:			
Change in operating assets and liabilities	1,247	(45)	2,790
Interest expense	3,246	4,591	792
Advisory services agreement termination fee	2,500		
Realized (gain) loss on early termination of commodity derivatives	2,998		
Special distribution to holders of LTIP phantom units	1,624		
Transaction costs	282	303	6,404
Deduct:			

Cash interest expense (1)	3,246	4,591	792
Straight-line amortization of put costs (2)	409		
COMA income	879		
Integrity management costs (3)	1,500	1,500	250
Maintenance capital expenditures (4)	3,083	3,000	500
Distributable Cash Flow	13,212	9,549	1,913

(1) Excludes amortization of debt issuance costs and mark-to-market adjustments related to interest rate derivatives.
(2) Amounts noted represent the straight-line amortization of the cost of commodity put contracts over the life of the contract.
(3) Amounts noted represent average estimated integrity management costs over the 7 year mandatory testing cycle.
(4) Amounts noted represent estimated annual maintenance capital expenditures of $3.5 million which is what we expect to be required to maintain our assets over the long term.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented and those of our Predecessor may not be comparable, either to each other or to our future results of operations, for the reasons described below:

Since we acquired our assets from Enbridge effective November 1, 2009, the financial and operational data for 2009 that is discussed below is generally bifurcated between the period that our Predecessor owned those assets and the period from our acquisition through the end of the year. Moreover, there is some overlap between these two periods resulting from the fact that we were formed on August 20, 2009, which was prior to the acquisition on November 1, 2009. As a result, the 2009 period that our Predecessor owned and operated the assets is the ten months ended October 31, 2009, while the successor 2009 period begins with our inception on August 20, 2009 and ends on December 31, 2009. Although we incurred costs associated with our formation and the acquisition of our assets from Enbridge of $6.4 million, we had no material operations until November 1, 2009.

The historical combined financial information of our Predecessor:

- is presented on a combined rather than a consolidated basis. The principal difference between consolidated and combined financial statements is that consolidated financial statements do not reflect transactions and investments between consolidated subsidiaries or between those subsidiaries and the parent entity, showing instead a view of the parent entity and its consolidated subsidiaries as a whole; and

- reflects the operation of our assets with different business strategies and as part of a larger business rather than the stand-alone fashion in which we operate them.

SG&A expenses of our Predecessor during periods in which we did not own or operate our assets were allocated expenses from a much larger parent entity and may not represent SG&A expenses required to actually operate our assets as we intend.

After our initial public offering, we began incurring incremental general and administrative expenses attributable to operating as a publicly traded partnership, such as expenses associated with annual and quarterly SEC reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance costs; and director compensation.

In connection with our formation and the acquisition of our assets from Enbridge, we incurred transaction expenses of approximately $6.4 million. These transaction expenses are included in our historical consolidated financial statements for the period from August 20, 2009 to December 31, 2009.

In connection with the acquisition of our assets from Enbridge, effective November 1, 2009:

- we put in place stand-alone insurance policies customary for midstream partnerships, which had the effect of increasing our direct operating expenses;

- we initiated a comprehensive review of the integrity management program that we inherited when we acquired our assets. Following this review, we concluded that there were sixteen high consequence areas that required further testing pursuant to DOT regulations;

- one of our subsidiaries entered into an advisory services agreement with certain affiliates of AIM Midstream Holdings, which resulted in higher SG&A expenses during the periods after that acquisition. Please read Certain Relationships and Related Party Transactions Agreements with Affiliates. At the closing of our IPO, we paid $2.5 million to those affiliates and terminated this agreement; and

- we recorded our assets at fair value, which was less than our Predecessor s book value of those assets, and their useful lives were also decreased, which had the net effect of increasing the depreciation expense associated with our assets after the acquisition date.

Interest expense of our Predecessor was an allocated expense from our Predecessor s publicly traded parent entity. In addition, we incurred indebtedness to finance our acquisition of our assets from Enbridge, which increased our interest expense after the acquisition date.

After our acquisition of our assets from Enbridge, we initiated a hedging program comprised of NGL puts and swaps, as well as interest rate caps, that we account for using mark-to-market accounting. These amounts are included in our historical consolidated financial statements and related notes as unrealized/realized gain (loss) from risk management activities.

In November 2010, we completed the construction of the Winchester lateral into our Bazor Ridge processing plant. Since its completion, the lateral has provided approximately 4,000 MMcf/d of incremental gas into the Bazor Ridge plant.

In December 2010, we completed an interconnect between our Lafitte pipeline and a pipeline on the TGP interstate system. This interconnect enables us to purchase natural gas from producers on the TGP system and deliver it to the Alliance Refinery and the Toca processing plant, which will enable us to process substantially more natural gas under our elective processing arrangements.

On December 1, 2011, we acquired a 50% undivided interest in the Burns Point Plant from Marathon Oil Company for total cash consideration of $35.5 million. No liabilities of the Seller were assumed. The purchase was effective November 1, 2011.

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Outlook

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic downturn that led to a decline in worldwide energy demand. During this same period, North American oil and natural gas supply was increasing as a result of the rise in domestic unconventional production. The combination of lower energy demand due to the economic downturn and higher North American oil and natural gas supply resulted in significant declines in oil, NGL and natural gas prices. While oil and NGL prices began to increase steadily in the second quarter of 2009, natural gas prices remained depressed and volatile throughout 2009 and 2010 in comparison to much of 2007 and 2008 due to a continued increase in natural gas supply despite weaker offsetting demand growth. The outlook for a worldwide economic recovery in 2012 remains uncertain, and the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, we expect natural gas prices to remain relatively low in the near term.

Notwithstanding the ongoing volatility in commodity prices, there has been a recent resurgence in the level of acquisition and divestiture activity in the midstream energy industry and we expect that trend to continue. In particular, we believe that opportunities to acquire midstream energy assets from third parties that fulfill our strategic objectives will continue to arise in the foreseeable future.

Supply and Demand Outlook for Natural Gas and Oil

Natural gas and oil continue to be critical components of energy consumption in the United States. According to the U.S. Energy Information Administration, or EIA, annual consumption of natural gas in the U.S. was approximately 24.4 trillion cubic feet, or Tcf, in 2011, compared to approximately 24.1 Tcf in 2010, representing an increase of approximately 1.2%. Domestic production of natural gas grew from approximately 22.6 Tcf in 2010 to approximately 24.4 Tcf in 2011, or an 8.0% increase. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States, representing approximately 59.0% of the total natural gas consumed in the United States during 2011. In particular, based on a report by the EIA, industrial natural gas demand is expected to grow from 7.3 Tcf in 2009 to 9.4 Tcf in 2020 as a result of an expected recovery in industrial production.

According to the EIA, domestic crude oil production was approximately 5.7 million barrels per day, or MMBbl/d, in 2011, compared to approximately 5.5 MMBbl/d in 2010, representing an increase of approximately 3.6%. Domestic crude oil production is expected to continue to increase over time primarily due to improvements in technology that have enabled U.S. onshore producers to economically extract sources of supply, such as secondary and tertiary oil reserves and unconventional oil reserves, that were previously unavailable or uneconomic.

We believe that current oil and natural gas prices and the existing demand for oil and natural gas will continue to result in ongoing oil and natural gas-related drilling in the United States as producers seek to increase their production levels. In particular, we believe that drilling activity targeting natural gas with modest to high NGL content, such as on our Gloria system, and targeting oil with associated natural gas, such as on our Bazor Ridge system, will remain active. Although we anticipate continued exploration and production activity in the areas in which we operate, fluctuations in energy prices can affect natural gas production levels over time as well as the timing and level of investment activity by third parties in the exploration for and development of new oil and natural gas reserves. We have no control over the level of oil and natural gas exploration and development activity in the areas of our operations.

Impact of Interest Rates

The credit markets recently have experienced near-record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. If this occurs, interest rates on floating rate credit facilities and future offerings in the debt capital markets could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price will be impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, reduce debt or for other purposes.

Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Results of Operations   Combined Overview

Our distributable cash flow for the year ended December 31, 2011 was $13.2 million. Operating results for the year ended December 31, 2011 showed significant increases over operating results for the year ended December 31, 2010. For the year ended December 31, 2011, gross margin increased 21.2% from that of 2010. This positive performance was tempered, in part, by an unusual set of operational issues, both ours and third party s that reduced gathering and processing volumes which in turn impacted our financial performance in the third quarter 2011.

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

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

The following table and discussion presents certain of our historical consolidated financial data for the periods indicated. The results of operations by segment are discussed in further detail following this combined overview.

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	2011	2010		
	(in thousands)			
Statement of Operations Data:				
Revenue	$ 248,282	$ 212,248	$ 32,833	$ 143,132
Realized gain (loss) on early termination of commodity derivatives	(2,998)			
Unrealized gain (loss) on commodity derivatives	(541)	(308)		
Total revenue	244,743	211,940	32,833	143,132
Operating expenses				
Purchases of natural gas, NGLs and condensate	202,403	173,821	26,593	113,227
Direct operating expenses	12,856	12,187	1,594	10,331
Selling, general and administrative expenses	10,794	7,120	1,196	8,553
Advisory services agreement termination fee	2,500			
Transaction expenses	282	303	6,404	
Equity compensation expense (a)	3,357	1,734	150	
Depreciation expense	20,705	20,013	2,978	12,630
Total operating expenses	252,897	215,178	38,915	144,741
Gain (loss) on acquisition of assets	565			
Gain (loss) on sale of assets, net	399			
Operating income (loss)	(7,190)	(3,238)	(6,082)	(1,609)
Interest (expense)	(4,508)	(5,406)	(910)	(3,728)
Net income (loss)	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
Other Financial Data:				
Gross margin (b)	$ 46,187	$ 38,119	$ 6,240	$ 29,905
Adjusted EBITDA (c)	$ 21,041	$ 18,263	$ 3,450	$ 11,021
Distributable cash flow (d)	$ 13,212	$ 9,549	$ 1,913	

(a) Represents cash and non-cash costs related to our LTIP. Of these amounts, $1.6 million, $1.2 million and $0.2 million, for the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, respectively, were non-cash expenses.

(b) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 18 to our audited consolidated financial statements included in this Annual Report beginning on page F-1 for a discussion of how we use gross margin to evaluate our operating performance, please read How We Evaluate Our Operations .

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

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

Year ended December 31, 2011 compared to year ended December 31, 2010

Revenue. Our total revenue for the year ended December 31, 2011 was $244.7 million compared to $211.9 million for the year ended December 31, 2010. This increase of $32.8 million was primarily due to higher NGL sales volumes from owned processing facilities, higher realized NGL prices and natural gas sales volumes in our Gathering and Processing segment and higher natural gas sales gas sales volumes in our Transmission segment. This increase in revenue was also a result of a $0.5 million increase in COMA income. This increase was partially offset by lower realized natural gas prices in our Gathering and Processing segment and one-time $3.0 million charge resulting from the unwind and reset of our commodity hedge contracts in June 2011.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $202.4 million compared to $173.8 million in the year ended December 31, 2010. This increase of $28.6 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes in our Gathering and Processing and Transmission segments. This increase was partially offset by lower natural gas purchase costs in our Gathering and Processing segment.

Gross Margin. Gross margin for the year ended December 31, 2011 was $46.2 million compared to $38.1 million for the year ended December 31, 2010. This increase of $8.1 million was primarily due to higher throughput volume and associated NGL production from owned processing plants, improved processing and POP margins from higher NGL and condensate prices and higher throughput in our Gathering and Processing segment. We also achieved incremental gross margin of $1.1 million associated with our acquisition of a 50% undivided, non-operating, interest in the Burns Point Plant effective November 1, 2011. In addition this increase was also attributable to a $0.5 million increase in COMA income.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2011 were $12.8 million compared to $12.2 million in the year ended December 31, 2010. This increase of $0.6 million was primarily due to: (i) $0.2 million incremental costs related to service fees and costs to address operational matters; (ii) $0.3 million of added expenses associated with our 50% interest in the operating costs incurred at the Burns Point Plant; and (iii) $0.4 million of line losses in our Transmission segment. The operational cost increases were partially offset by a reduction in personnel related costs.

Selling, General and Administrative Expenses. SG&A expenses for the year ended December 31, 2011 were $10.8 million compared to $7.1 million for the year ended December 31, 2011. This increase of $3.7 million was primarily due to: (i) $1.9 million of incremental personnel costs and related benefits necessary to operate and grow a public company; (ii) $0.2 million in additional expenses associated with maintaining operational locations and services; (iii) $1.0 million of added costs associated with our IPO process and continued compliance and requirements for a publicly traded company; and (iv) $0.3 million of incremental costs associated with outside services and contract labor to assist in maintaining and maximizing operational efficiency of our systems.

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

Equity Compensation Expense. Compensation expense related our LTIP for the year ended December 31, 2011 was $3.4 million compared to $1.7 million for the year ended December 31, 2010. This increase of $1.7 million was primarily due to buy-out of distribution equivalent rights (DER s) associated with unvested phantom units at a cost of $1.5 million, a payment to holders of unvested phantom units without DER s of $0.1 million, increased amortization of $0.1 million associated with March 2011 phantom unit grants, off-set in part by the lack of DER payments in the second half of 2011 and a modification in amounts amortized due to the elimination of the DER s.

Depreciation Expense. Depreciation expense in the year ended December 31, 2011 was $20.7 million compared to $20.0 million for the year ended December 31, 2010. This increase of $0.7 million was due to depreciation associated with capital projects placed into service during the period.

Year Ended December 31, 2010 Compared to the 2009 Successor Period and the 2009 Predecessor Period

Revenue. Our total revenue in 2010 was $211.9 million compared to $32.8 million and $143.1 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily due to higher realized NGL prices in our Gathering and Processing segment and a new fixed-margin contract in our Transmission segment. Under our fixed-margin contracts, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical quantity of natural gas at delivery points on our systems at the same undiscounted index price. This increase was partially offset by lower throughput and processing volumes in our Gathering and Processing segment and lower NGL production.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for 2010 were $173.9 million compared to $26.6 million and $113.2 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily the result of a new fixed-margin contract in our Transmission segment and higher realized NGL prices in our Gathering and Processing segment, and was partially offset by lower throughput and processing volumes in our Gathering and Processing segment.

Gross Margin. Gross margin in 2010 was $38.1 million, compared to $6.2 million and $29.9 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily due to higher realized NGL prices in our Gathering and Processing segment, which positively impacted the segment gross margin associated with our percent-of-proceeds arrangements, and was partially offset by lower throughput and processing volumes in our Gathering and Processing segment. In addition, segment gross margin in our Transmission segment was higher in 2010 due to increased throughput volumes on our regulated pipelines as a result of colder weather. The increases in revenue and purchases of natural gas, NGLs and condensate that were driven by higher realized commodity prices and the new fixed-margin contract in our Transmission segment had minimal impact on gross margin.

Direct Operating Expenses. Direct operating expenses in 2010 were \$12.2 million, compared to \$1.6 million and \$10.3 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily due to higher fixed costs, such as insurance and higher maintenance expenses that we incurred following our acquisition of our assets in our Transmission segment, partially offset by lower outside services costs in our Gathering and Processing segment.

Selling, General and Administrative Expenses. SG&A expenses in 2010 were $7.1 million, compared to $1.2 million and $8.6 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. The decrease in SG&A expenses was a result of our incurrence of actual SG&A expenses compared to the historical allocation of SG&A expenses by the owner.

Equity Compensation Expense. Compensation expense related our LTIP for the year ended December 31, 2010 was $1.7 million and $0.2 million in the 2009 Successor Period, respectively. Because we adopted the LTIP in November 2009, there were no LTIP expenses in the 2009 Predecessor Period.

One-Time Transaction Expenses. We incurred approximately $6.4 million of one-time expenses, including legal, consulting and accounting fees in the 2009 Successor Period in connection with our acquisition of our assets. An additional $0.3 million was recorded in 2010 primarily related to Predecessor audit fees and remaining asset valuation costs.

Depreciation Expense. Depreciation expense was $20.0 million in 2010 compared to $3.0 million and $12.6 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. We recorded our assets at fair value, which was less than our Predecessor s book value of those assets, and their useful lives were also decreased, which had the net effect of increasing the depreciation expense associated with our assets after the acquisition date. The increase in depreciation expense from 2009 to 2010 is attributable to those adjustments.

Results of Operations Segment Results

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

	For the Year Ended December 31, 2011	For the Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	(in thousands except operational data)			
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$ 181,517	$ 158,763	$ 27,857	$ 132,957
Realized gain (loss) on early termination of commodity derivatives	(2,998)			
Unrealized gain (loss) on commodity derivatives	(541)	(308)		
Total revenue	177,978	158,455	27,857	132,957
Purchases of natural gas, NGLs and condensate	$ 149,374	$ 133,860	$ 24,159	$ 112,933
Direct operating expenses	$ 7,636	$ 7,721	$ 956	$ 7,134
Other financial data:				
Segment gross margin	$ 32,450	$ 24,595	$ 3,698	$ 20,024
Operating data:				
Average throughput (MMcf/d)	250.9	175.6	169.7	211.8
Average plant inlet volume (MMcf/d) (a)	36.7	9.9	11.4	11.7
Average gross NGL production (Mgal/d) (a)	54.5	34.1	38.2	39.3
Average realized prices:				
Natural gas ($/MMcf)	$ 4.09	$ 4.61	$ 4.71	$ 3.76
NGLs ($/gal)	$ 1.32	$ 1.08	$ 1.05	$ 0.70
Condensate ($/gal)	$ 2.41	$ 1.82	$ 1.68	$ 1.16
Transmission segment				
Financial data:				
Total revenue	$ 66,765	$ 53,485	$ 4,976	$ 10,175
Purchases of natural gas, NGLs and condensate	$ 53,029	$ 39,961	$ 2,434	$ 294
Direct operating expenses	$ 5,220	$ 4,466	$ 638	$ 3,197
Other financial data:				
Segment gross margin	$ 13,737	$ 13,524	$ 2,542	$ 9,881
Operating data:				
Average throughput (MMcf/d)	381.1	350.2	381.3	357.6
Average firm transportation - capacity reservation (MMcf/d)	702.2	677.6	701.0	613.2
Average interruptible transportation - throughput (MMcf/d)	69.0	80.9	118.0	121.0

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2011 was $177.9 million compared to $158.5 million for the year ended December 31, 2010. This increase of $19.4 million was, in part, due to higher throughput and associated increased NGL sales volumes at our Bazor Ridge plant due to the completion of our Winchester laterial in the fourth quarter of 2010 and the production from several new wells drilled on the system in 2011. Revenue in our Gathering and Processing segment also increased as a result of higher realized NGL and condensate prices which increased revenues at our owned processing plants and the volumes associated with our elective processing agreements. Revenues also increased as a result of higher natural gas sales volumes, primarily the increased demand at the Conoco Alliance refinery, which we serve with production from our Lafitte system and our interconnect with the Tennessee Gas Pipeline. This increase was partially offset by lower realized natural gas prices.

Total natural gas throughput volumes on our Gathering and Processing segment were 250.9 MMcf/d during the year ended December 31, 2011 compared to 175.6 MMcf/d during the year ended December 31, 2010. Natural gas inlet volumes at our owned processing plants were 36.7 MMcf/d during the year ended December 31, 2011 compared to 9.9 MMcf/d for the year ended December 31, 2010. Gross NGL production volumes from our owned processing plants were 54.5M gal/d during the year ended December 31, 2011 compared to 34.1 Mgal/d during the year ended December 31, 2010. Primary factors influencing these gains were:

The connection of additional Contango production on our Quivira system in the third quarter 2010 representing a 43% increase year over year;

new incremental throughput volume from the Burns Point Plant from the 50% interest we acquired effective November 1, 2011;

an increase in volume across our Lafitte and Gloria systems as a result of higher natural gas demand at the Conoco Alliance refinery and incremental volume sourced from our interconnect with Tennessee Gas Pipeline, which combined to increase volumes across the systems by 28% per year; and

the completion of the Winchester lateral on our Bazor Ridge system in the fourth quarter 2010, combined with the connection of the two new wells in the first and second quarter 2011, which contributed to a 46% increase year over year.

The average realized price of natural gas for the year ended December 31, 2011 was $4.09/Mcf, compared to $4.61 /Mcf for the year ended December 31, 2010. The average realized price of NGLs for the year ended December 31, 2011 was $1.32/gal, compared to $1.08/gal for the year ended December 31, 2010. The average realized price of condensate for the year ended December 31, 2011 was $2.41/gal, compared to $1.82/gal for the year ended December 31, 2010.

We entered into a series of swap and put contracts in January 2011 and swap contracts again in June 2011. These commodity derivative transactions had a negative net effect of $0.8 million on our revenue related to unrealized losses for the year ended December 31, 2011. In June 2010, we purchased put contracts that extended through June 2011. For the year ended December 31, 2010 we recognized an unrealized valuation loss of $0.3 million related to this contract.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $149.4 million compared to $133.9 million for the year ended December 31, 2010. This increase of $15.5 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants POP contracts and higher natural gas purchase volumes to provide natural gas for the Conoco Alliance refinery. This increase was partially offset by lower natural gas prices.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2011 was $32.5 million compared to $24.6 million for the year ended December 31, 2010. This increase of $7.9 million was primarily due to higher throughput volume and associated NGL production at our Bazor Ridge processing plant, increased throughput volume on our Quivira system, higher realized NGL prices which positively impacted margins associated with our POP and elective processing agreements, and the acquisition of our 50% interest in the Burns Point Plant in November 2011. In addition, a $0.3 million unrealized loss on commodity derivatives was recognized in 2010. Beginning January 1, 2011, such unrealized losses are excluded from segment gross margin. Gathering and Processing segment represented 70.3% of our total gross margin for the year ended December 31, 2011, compared to 64.5% for the year ended December 31, 2010.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2011 were $7.6 million compared to $7.7 million for the year ended December 31, 2010.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2011 was $66.8 million compared to $53.5 million for the year ended December 31, 2010. Total natural gas throughput on our Transmission systems for the year ended December 31, 2011 was 381.1MMcf/d compared to 350.2 MMcf/d in the year ended December 31, 2010. This increase of $13.3 million in revenue was primarily due to a full year s impact of our fixed margin agreement which began in the second quarter 2010 to supply gas to Exxon on our MLGT system offset in part by lower volumes and natural gas prices associated with an affiliate fixed margin agreement on the Midla system. Our commodity derivatives had no effect on segment revenue for the years ended December 31, 2011 and 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $53.0 million compared to $40.0 million for the year ended December 31, 2010. This increase of $13.0 million was primarily due to a full year s impact of our fixed margin agreement began in the second quarter 2010 to supply gas to Exxon on our MLGT system offset in part by lower volumes and natural gas prices associated with an affiliate fixed margin agreement on the Midla system.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2011 was $13.7 million compared to $13.5 million for the year ended December 31, 2010. Segment gross margin for the Transmission segment represented 29.7% of our total gross margin for year ended December 31, 2011, compared to 35.5% for the year ended December 31, 2010.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2011 were $5.2 million compared to $4.5 million for the year ended December 31, 2010. This increase of $0.7 million was primarily due to $0.2 million incremental costs related to service fees and costs to address operational matters and a $0.5 million increase in line losses.

Year Ended December 31, 2010 Compared to the 2009 Successor Period and the 2009 Predecessor Period

Gathering and Processing Segment

Revenue. Segment revenue for 2010 was $158.5 million compared to $27.9 million and $133.0 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This decrease was primarily due to decreased throughput and processing volumes on our Bazor Ridge system due to unplanned downtime caused by the pipeline rupture that occurred in April 2010. Please see Risk Factors Risks Related to Our Business Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured, our operations and financial results could be adversely affected for more information regarding the Bazor Ridge pipeline rupture. This decrease in revenue was partially offset by higher realized NGL prices across this segment. Set forth below is a comparison of the volumetric and pricing data for the year ended December 31, 2010, and the 2009 Successor Period and the 2009 Predecessor Period.

Total natural gas throughput volumes on our Gathering and Processing segment were 175.6 MMcf/d in 2010 compared to 169.7 MMcf/d and 211.8 MMcf/d in the 2009 Successor Period and the 2009 Predecessor Period, respectively. Natural gas inlet volumes at our owned processing plants were 9.9 MMcf/d in 2010 compared to 11.4 MMcf/d and 11.7 MMcf/d in the 2009 Successor Period and the 2009 Predecessor Period, respectively. Gross NGL production volumes from our owned processing plants were 34.1 Mgal/d in 2010 compared to 38.2 Mgal/d and 39.3 Mgal/d in the 2009 Successor Period and the 2009 Predecessor Period, respectively.

The average realized price of natural gas in 2010 was $4.61/MMcf, compared to $4.71/MMcf and $3.76/MMcf for the 2009 Successor Period and the 2009 Predecessor Period, respectively. The average realized price of NGLs in 2010 was $1.08/gal, compared to $1.05/gal and $0.70/gal for the 2009 Successor Period and the 2009 Predecessor Period, respectively.

Our hedges had no effect on our revenue for the year ended December 31, 2010. We and our Predecessor had no hedges during the 2009 Successor Period and 2009 Predecessor Period, respectively.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for 2010 were $133.9 million compared to $24.2 million and $112.9 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This decrease in purchases of natural gas, NGLs and condensate was primarily driven by lower throughput and processing volumes on our Bazor Ridge system and lower fixed-margin volumes on our Lafitte system, partially offset by higher realized NGL prices across the segment.

Segment Gross Margin. Segment gross margin for 2010 was $24.6 million compared to $3.7 million and $20.0 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was largely due to higher realized NGL prices that had a positive impact on segment gross margin associated with percent-of-proceeds contracts on our Bazor Ridge and Gloria systems. In addition, natural gas prices were lower in 2010, which had a net positive impact on natural gas we processed under our elective processing arrangements. We also received additional segment gross margin associated with the construction of our Atmore processing plant that commenced operation in June 2010. This increase was partially offset by lower throughput volumes across most of our gathering systems due to well declines and reduced drilling activity due to lower natural gas prices as well as lower volumes on our Bazor Ridge system largely resulting from a pipeline rupture. Segment gross margin for the Gathering and Processing segment represented 64.5% of our gross margin for 2010, compared to 59.3% and 67.0%, respectively, for the 2009 Successor Period and the 2009 Predecessor Period.

Direct Operating Expenses. Direct operating expenses for 2010 were $7.7 million compared to $1.0 million and $7.1 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This decrease in direct operating expenses was primarily due to lower outside services costs.

Transmission Segment

Revenue. Segment revenue for 2010 was $53.5 million compared to $5.0 million and $10.2 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. Total natural gas throughput on our Transmission systems for 2010 was 350.2 MMcf/d compared to 381.3 MMcf/d and 357.6 MMcf/d in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase in revenue was primarily due to the new fixed-margin contract in our Transmission segment 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. This increase in revenue was partially offset by a decrease in volumes transported pursuant to fee-based and fixed-margin arrangements. Our hedges had no effect on our revenue for the year ended December 31, 2010. We and our Predecessor had no hedges during the 2009 Successor Period and 2009

Predecessor Period, respectively.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for 2010 were $40.0 million compared to $2.4 million and $0.3 million in the 2009 Successor Period and 2009 Predecessor Period, respectively. As part of our fixed-margin arrangements, we purchase natural gas, but not NGLs or condensate, in our Transmission segment. This increase was primarily due to the new fixed-margin arrangement on our MLGT system.

Segment Gross Margin. Segment gross margin for 2010 was $13.5 million compared to $2.5 million and $9.9 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily due to an increase in seasonally-adjusted rates and reservation volumes as a result of colder weather in markets served by our AlaTenn and Midla systems. During periods of unseasonably cold weather, some shippers exceeded their maximum contract quantities and had to secure higher priced transport capacity to meet demand, thereby increasing our segment gross margin. Segment gross margin in our Transmission segment represented 35.5% of our gross margin for 2010, compared to 40.7% and 33.0% for the 2009 Successor Period and the 2009 Predecessor Period, respectively.

Direct Operating Expenses. Direct operating expenses for 2010 were $4.5 million compared to $0.6 million and $3.2 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase was primarily due to incremental insurance costs that we had to incur and allocate to our assets.

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 December 31, 2011 were our cash on hand and availability under our new credit facility as discussed below. As of December 31, 2011, our available liquidity was $28.2 million, comprised of cash on hand less $0.5 million and $27.8 million available under our new credit facility. As of February 29, 2012, our available liquidity was $26.3 million. In the near term, we expect our sources of liquidity to include cash generated from operations, borrowings under our new credit facility and issuances of debt and equity securities. We believe that the cash generated from these sources will be sufficient to allow us to distribute the minimum quarterly distribution on all of our outstanding common and subordinated units, the corresponding distribution on our 2.0% general partner interest and meet our requirements for working capital and capital expenditures over the next 12 months.

Our credit facility also provides for a $50 million accordion feature for accretive growth projects. If the accordion feature were to be fully exercised and approved by our lenders, the total commitment under the new facility would be $150 million.

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 $2.7 million at December 31, 2011.

Cash Flows

The following table reflects cash flows for the applicable periods:

	For the Year Ended December 31,		Period from August 20, 2009 (Inception Date) to December 31,	Predecessor Ten Months ended October 31,
	2011	2010	2009	2009
Net cash provided by (used in):				
Operating activities	$ 10,432	$ 13,791	$ (6,531)	$ 14,589
Investing activities	(41,744)	(10,268)	(151,976)	(853)
Financing activities	32,120	(4,609)	159,656	(14,008)

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Operating Activities. Net cash provided by (used in) operating activities was $10.4 million for year ended December 31, 2011 compared to $13.8 million for the year ended December 31, 2010. The change in cash provided by (used in) operating activities was primarily a result of the combined effects of a net loss, net of non-cash changes, in addition to net positive changes in operating assets and liabilities. In addition, $3.0 million was used to terminate our NGL swaps with two counterparties, purchase an NGL put for $0.7 million, $1.5 million was used to pay holders of phantom units under our LTIP in consideration for the elimination of the DER provision in existing LTIP agreements and $2.5 million was used to buy-out the management agreement with AIM.

Investing Activities. Net cash provided by (used in) investing activities was ($41.7) million for the year ended December 31, 2011 compared to ($10.3) million for the year ended December 31, 2010. Cash provided by (used in) investing activities for the year ended December 31, 2011 was primarily a result of the purchase of a 50% undivided non-operating interest in the Burns Point plant for $35.5 million, a meter relocation costing $2.3 million on our MLGT system, $1.4 million for pipeline relocation work on our Gloria and Chalmette systems associated with levee improvements and $0.2 million for a Gloria compressor overhaul.

Financing Activities. Net cash provided by (used in) financing activities was $32.1 million for the year ended December 31, 2011 compared to ($4.6) million for the year ended December 31, 2010. The change in cash provided by (used in) financing activities was primarily a result of $69.1 million in net proceeds from our IPO, a decrease in other unit holder contributions of ($12.0), the ($58.6) million pay down of our $85 million credit facility, an initial draw of $30.0 million from our new $100 Million Credit Facility, debt issuance costs of ($2.5) million, a $14.5 million increase in net borrowings of long-term debt and an increase of ($31.7) million in distributions made to our unitholders.

Year Ended December 31, 2010 Compared to the 2009 Successor Period and the 2009 Predecessor Period

Operating Activities. Net cash provided by (used in) operating activities was $13.8 million for the year ended December 31, 2010 compared to ($6.5) million and $14.6 million for the 2009 Successor Period and 2009 Predecessor Period, respectively. 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 charges, in addition to net positive changes in operating assets and liabilities.

Investing Activities. Net cash provided by (used in) investing activities was ($10.3) million for the year ended December 31, 2010 compared to ($152.0) million and ($0.9) million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The change in cash used in investing activities was primarily a result of our acquisition of our assets in November 2009 for cash consideration of $150.8 million and the construction of the Winchester lateral in November 2010.

Financing Activities. Net cash provided by (used in) financing activities was ($4.6) million for the year ended December 31, 2010 compared to $159.7 million and ($14.0) million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The change in cash provided by (used in) financing activities was primarily a result of net borrowings under our credit facility of $61.0 million and a capital contribution of $100.0 million by AIM Midstream Holdings in connection with our acquisition of our assets and funding our initial working capital requirements in November 2009. During the year ended December 31, 2010, AIM Midstream Holdings contributed an additional $12.0 million to us, we made approximately $5.0 million of amortization payments under the term loan portion of our existing credit facility and we made distributions of $11.8 million to our unitholders.

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. For the year ended December 31, 2011, our capital expenditures exclusive of our purchase of the 50% undivided interest in the Burns Point Plant totaled $6.4 million including expansion capital expenditures of $0.5 million, maintenance capital expenditures of $2.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a 3rd party) of $3.8 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our partnership agreement.

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.

Integrity Management

When we acquired our operating assets from Enbridge, we inherited an ongoing integrity management program required under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our current program will be completed in 2012. In connection with the acquisition of our assets from Enbridge we initiated a comprehensive review of the program and concluded that there were sixteen high consequence areas, or HCAs, in addition to those identified by our Predecessor that required further testing pursuant to DOT regulations. We expect to incur $0.1 million in integrity management expenses in 2012 associated with these HCAs to complete the current integrity management program.

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

Because DOT regulations require integrity management activities for each HCA to be performed within seven years from when they were last performed, we expect to incur the following expenses:

Year	Integrity Management Expense (in thousands)
2013	$ 2,000
2014	5,015
2015	839
2016	675
2017	
2018	
2019	2,080
Total	$ 10,609

In conjunction with the commencement of our next seven-year integrity management program cycle in 2013, we plan to request the DOT s consent to a modification of the timing of our integrity management expenses so that we spend approximately $1.5 million each year.

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 distributions though we do not have a legal obligation to make distributions except as provided in our partnership agreement.

Our post initial public offering distributions consisted of a pro-rated distribution in November 2011 for the period from August 2, 2011 through September 30, 2011 of $0.2690 per unit, or $2.5 million and a distribution in February 2012 for the fourth quarter 2011 of $0.4325 per unit or $4.0 million.

Our Credit Facility

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

The credit facility provides for a maximum borrowing equal to the lesser of (i) $100 million or (ii) 4.50 times adjusted consolidated EBITDA. We may elect to have loans under the credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.25% to 3.50% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 1/2 of 1%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its prime rate , and (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.25% to 2.50% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

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, August 1, 2016.

The credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are (i) a total leverage ratio test (not to exceed 4.50 times) and a minimum interest coverage ratio test (not less than 2.50 times). We were in compliance with all of the covenants under our credit facility as of December 31, 2011.

Credit Risk

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to which we provide services and sell commodities. Our three largest purchasers of natural gas in our Gathering and Processing segment are ConocoPhillips, Enbridge Marketing (US) L.P. and Dow Hydrocarbons and Resources and accounted for approximately 55%, 16% and 9%, respectively, of our segment revenue for the year ended December 31, 2011. Additionally, Enbridge Marketing US, ExxonMobil and Calpine Corporation are the two largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 22%, 57% and 8%, respectively, of our segment revenue for the year ended December 31, 2011. We examine the creditworthiness of third-party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

Customer Concentration

A significant percentage of the gross margin in each of our segments is attributable to a relatively small number of customers. In our Gathering and Processing segment, Venture Oil & Gas Co.,and Contango Operators Inc.accounted for approximately 21% and 18%, respectively, of our segment gross margin for the year ended December 31, 2011. In our Transmission segment, Calpine Corporation accounted for approximately 37% of our segment gross margin for the year ended December 31, 2011. Although we have gathering, processing or transmission contracts with each of these customers of varying duration, if one or more of these customers were to default on their contract or if we were unable to renew our contract with one or more of these customers on favorable terms, we may not be able to replace any of these customers in a timely fashion, on favorable terms or at all. In any of these situations, our gross margin and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2011:

	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
			(in thousands)		
Long term debt	$ 66,270	$	$	$ 66,270	$
Operating leases and service contract	1,774	415	1,105	254	
Asset retirement obligation (ARO)	8,093			8,093	
Total	$ 76,137	$ 415	$ 1,105	$ 74,617	$

Impact of Seasonality

Results of operations in our Transmission segment are directly affected by seasonality due to higher demand for natural gas during the winter months, primarily driven by our LDC customers. On our AlaTenn system, we offer some customers seasonally-adjusted firm transportation rates that require customers to reserve capacity at rates that are higher in the period from October to March compared to other times of the year. On our Midla system, we offer customers seasonally-adjusted firm transportation reservation volumes that allow customers to reserve more capacity during the period from October to March compared to other times of the year. The combination of seasonally-adjusted rates and reservation volumes, as well as higher volumes overall, result in higher revenue and segment gross margin in our Transmission segment during the period from October to March compared to other times of the year. We generally do not experience seasonality in our Gathering and Processing segment.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our and our Predecessor s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by our and Predecessor s management to be critical to an understanding of the financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect our reported financial positions and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenue and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing tangible and intangible assets for possible impairment, (4) estimating the useful lives of our assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from our estimates.

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment is depreciated using the straight-line method over the estimated useful lives of the assets. The costs of renewals and betterments which extend the useful life of property, plant and equipment are also capitalized. The costs of repairs, replacements and maintenance projects are expensed as incurred.

Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values which would impact future depreciation expense.

Impairment of Long-Lived Assets. We assess our long-lived assets for impairment on authoritative guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market price of a long-lived asset or asset group;

- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;

- a significant adverse change in legal factors or in the business climate could affect the value of a long-lived asset or asset group, including an adverse action or assessment by a regulator which would exclude allowable costs from the rate-making process;

- as accumulation of costs significantly in excess of the amount originally expected for the for the acquisition or construction of the long-lived asset or asset group;

- a current-period operating cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group; and a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

We incurred no impairment charges during the years ended December 31, 2011 and 2010.

Environmental Remediation. Current accounting guidelines require us to recognize a liability and expense associated with environmental remediation if (i) government agencies mandate such activities, (ii) the existence of a liability is probable and (iii) the amount can be reasonably estimated. As of December 31, 2011 we have recorded no liability for remediation expenditures. If governmental regulations change, we could be required to incur remediation costs which may have a material impact on our profitability.

Asset Retirement Obligations. As of December 31, 2011, we have recorded liabilities of $8.1 million for future asset retirement obligations associated with our pipeline assets. Related accretion expense has been recorded in interest expense as discussed in Note 1 in our consolidated financial statements. The recognition of an asset retirement obligation requires that management make numerous estimates, assumptions and judgments regarding such factors as costs of remediation, timing of settlement to changes in the estimate of the costs of remediation. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset or corresponding liability on a prospective basis and an adjustment in our depreciation expense in future periods.

Equity-Based Awards. We account for equity-based awards in accordance with applicable guidance, which establishes standards of accounting for transactions in which an entity exchanges its equity instruments for goods or services. Equity-based compensation expense is recorded based upon the fair value of the award at grant date. Such costs are recognized as expense on a straight-line basis over the corresponding vesting period.

During 2010 and 2009, the fair values of the phantom-unit grants that we made were calculated based on several valuation models, including a discounted cash flow, or DCF, model, a comparable company multiple analysis and a comparable transaction multiple analysis. The DCF model included 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 comparable 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 distributable cash flow) and certain assumptions in the calculation of enterprise value. The initial valuation of $10.00 per common unit was prepared in August 2009 in connection with our formation in anticipation of the acquisition of our assets from a subsidiary of Enbridge Energy Partners, L.P. In November 2009, we received indirect third-party investments at that same valuation in connection with the acquisition of our assets from Enbridge. We assessed the adequacy of that valuation on each grant date subsequent to the initial fair value calculation to determine if events or circumstances had occurred that would cause that valuation to become less relevant, noting none. Moreover, we received additional indirect third-party investments at $10.00 per common unit in each of September and November 2010. As a result, we maintained that $10.00 valuation for phantom-unit grants made in November 2009, March 2010 and October 2010.

For the phantom-unit grants made during March 2011, the fair values of the grants were calculated by affiliates of our general partner as $13.67 per common unit based on several valuation models as of December 31, 2010, including a DCF model, a comparable company multiple analysis and a comparable transaction multiple analysis. The DCF 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 comparable 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 distributable cash flow) and certain assumptions in the calculation of enterprise value. The year-end 2010 valuation was completed in January 2011. We assessed the adequacy of that valuation in connection with the March 2011 grant date to determine if events or circumstances had occurred since December 31, 2010 that would cause that valuation to become less relevant, noting none.

Revenue Recognition. 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 the gross basis for those transactions where we act as the principal and take title to natural gas, NGLs or condensates that is 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 revenue. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer.

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

Natural Gas Imbalance Accounting. Quantities of natural gas over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices at the time the imbalance was created. Monthly, gas imbalances over-delivered are valued at the lower of cost or market; gas imbalances under-delivered are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. Under the contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Price Risk Management Activities. We have structured our hedging activities in order to minimize our commodity pricing and interest rate risks and to help maintain compliance with certain financial covenants in our credit facility. These hedging activities rely upon forecasts of our expected operations and financial structure through December 2012. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed.

From the inception of our hedging program in December 2009, we used mark-to-market accounting for our commodity hedges and interest rate caps. We record monthly realized gains and losses on hedge instruments based upon cash settlements information. The settlement amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses quarterly based upon the future value on mark-to-market hedges through their expiration dates. The expiration dates vary but are currently no later than December 2012 for our commodity hedges. We monitor and review hedging positions regularly.

Recent Accounting Pronouncements

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

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

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate in our Gathering and Processing segment. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas and NGL prices are impacted by changes in the supply and demand for natural gas and NGLs, as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read Risk Factors. Adverse effects on our cash flow from reductions in natural gas and NGL product prices could adversely affect our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets, and the use of derivative contracts. Our overall direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our current contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing. In January 2011, we implemented a hedging program by entering into a number of financial hedges to protect our expected NGL production through mid-2012. Through these January 2011 hedge transactions, we executed swap and put contracts settled against the market prices of ethane, propane, iso-butane, normal butane and natural gasoline.

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.

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

Pursuant to our January 2011 hedge transactions and June 2011 hedge transactions, we have hedged approximately 87% of our expected exposure to NGL prices in 2012.

Also, see Note 5 to the audited consolidated financial statements included with this Annual Report beginning on page F-1 for additional discussion related to derivative instruments and hedging activities.

The table below sets forth certain information regarding our NGL fixed swaps as of December 31, 2011:

Commodity	Period	Notional Volumes (gal/d)	Weighted Average Price ($/gal) We Receive	We Pay	Fair Market Value December 31, 2011
Ethane	July 2011 - Dec 2012	7,300	$ 0.57	OPIS avg	$ (388,658)
Propane	July 2011 - Dec 2012	7,050	$ 1.40	OPIS avg	149,940
Iso-Butane	July 2011 - Dec 2012	2,510	$ 1.81	OPIS avg	(158,805)
Normal Butane	July 2011 - Dec 2012	3,000	$ 1.74	OPIS avg	(87,390)
Natural Gasoline	July 2011 - Dec 2012	5,500	$ 2.31	OPIS avg	216,654
Total		25,360	$ 1.44		$ (268,259)

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

The table below sets forth certain information regarding our NGL put as of December 31, 2011:

Commodity	Period	Notional Volumes (gal/d)	Floor Strike Price ($/gal)	Fair Market Value December 31, 2011
NGL basket	Feb 2011 to July 2012	9,800	$ 1.29	$ 89,512

Interest Rate Risk

During the year ended December 31, 2011, we had exposure to changes in interest rates on our indebtedness associated with our credit facilities. We anticipate that we will enter into new interest rate hedging contracts as necessary 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 $0.5 million for the year ended December 31, 2011.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the reports of our independent registered public accounting firm, begin on F-1 of this Annual Report.

Item 9. Changes in and Disagreements with Accountants and Financial Disclosure

None.

Item 9A. Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner s Chief Executive Officer (our principal executive officer) and our general partner s Vice President of Finance (our principal financial officer), as appropriate, to allow for timely decisions regarding required disclosure. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act of 1934 (the Exchange Act)) was performed as of December 31, 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 disclosure controls and procedures are effective to ensure that we are able to collect, process and disclose the information we are required to disclose in the reports we file with the SEC within the required time periods.

This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of the Partnership s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Changes in internal control

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2011 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 Annual Report on Form 10-K as Exhibits 31.1and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this Annual Report on Form 10-K as Exhibits 32.1 and 32.2.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are managed by the directors and executive officers of our general partner, American Midstream GP, LLC. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. AIM Midstream Holdings owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly participate in our management or operations. AIM, Eagle River Ventures, LLC, Stockwell Fund II, L.P. and certain of our executive officers own all of the membership interests in AIM Midstream Holdings. In addition, Messrs. Hellman, Carbone and Diffendal serve on the board of directors of our general partner and are principals of and have ownership interests in AIM. Our general partner owes certain fiduciary duties to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

Our partnership agreement provides for the conflicts committee of the board of directors of our general partner, or the Conflicts Committee, as delegated by the board of directors of our general partner as circumstances warrant, to review conflicts of interest between us and our general partner or between us and affiliates of our general partner. If a matter is submitted to the Conflicts Committee, which will consist solely of independent directors, for their review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the board of directors of our general partner is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our general partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, the board of directors of our general partner has an audit committee, that complies with the NYSE requirements or the Audit Committee, and a compensation committee of the board of directors, or the Compensation Committee.

Even though most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of its general partner.

Our general partner has adopted a Code of Business Conduct and Ethics, or Code of Ethics, that applies to the directors, officers and employees of our general partner. If the general partner amends the Code of Ethics or grants a waiver, including an implicit waiver, for the Code of Ethics, we will disclose the information on our website. Our general partner has also adopted Corporate Governance Guidelines that outline the important policies and proactices regarding our governance.

We make available free of charge, within the Investor Relations Corporate Governance section of our website at http://www.americanmidstream.com, and in print to any unitholder who so requests, the Code of Ethics and our Corporate Governance Guidelines. The information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Eileen A. Aptman, Edward O. Diffendal and Gerald A. Tywoniuk serve as members of the Audit Committee, with Mr. Tywoniuk serving as chairman. In compliance with the rules of the NYSE, the members of the board of directors will appoint one additional independent member to the board of directors by July 2012. Mr. Diffendal will resign from the Audit Committee when the final independent director is appointed. Thereafter, our general partner is generally required to have at least three independent directors serving on its board at all times. The board of directors of our general partner has determined that Gerald A. Tywoniuk is an audit committee financial expert. Gerald A. Tywoniuk is an independent director.

Robert B. Hellman, Jr. and L. Kent Moore serve as the members of the Compensation Committee; Mr. Hellman serving as chairman.

Matthew P. Carbone, Robert B. Hellman, Jr and David L. Page serve as members of the Compliance Committee, with Mr. Hellman serving as chairman.

Brian F. Bierbach, Edward O. Diffendal, Robert B. Hellman, Jr, and David L. Page serve as members of the Executive Committee, with David L. Page serving as chairman.

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board. The following table shows information for the directors and executive officers of our general partner.

Name	Age	Position with American Midstream GP, LLC
Robert B. Hellman, Jr.	52	Chairman of the Board
Brian F. Bierbach	54	Director, President and Chief Executive Officer
Sandra M. Flower	52	Vice President of Finance
John J. Connor II	54	Senior Vice President of Operations and Engineering
Marty W. Patterson	53	Senior Vice President of Commercial Services
William B. Mathews	59	Secretary, General Counsel and Vice President of Legal Affairs
Eileen A. Aptman	44	Director
Matthew P. Carbone	46	Director
Edward O. Diffendal	42	Director
David L. Page	77	Director
L. Kent Moore	56	Director
Gerald A. Tywoniuk	50	Director

Robert B. Hellman, Jr. was elected Chairman of the board of directors of our general partner in November 2009. Mr. Hellman has been a Managing Director of AIM since he co-founded AIM in July of 2006. Prior to co-founding AIM, Mr. Hellman was a Managing Director of McCown De Leeuw & Co., a private equity firm based in Foster City, California since 1986. Mr. Hellman is also chairman of the Board of Directors of Stonemor Partners L.P. Mr. Hellman received an MBA from Harvard University, an M.A. in Economics from the London School of Economics and a B.A. in Economics from Stanford University. We believe that Mr. Hellman s over 20 years of investing experience, as well as his in-depth knowledge of the midstream natural gas industry generally and our partnership in particular, provide him with the necessary skills to be a member of the board of directors of our general partner.

Brian F. Bierbach was appointed President and Chief Executive Officer, and elected as a member of the board of directors, of our general partner in November 2009. Prior to our formation, Mr. Bierbach served as President and as a member of the board of directors of Foothills Energy Ventures, LLC, a private midstream natural gas asset development and operating company, from 2006 to 2009. Mr. Bierbach has also served as President of Cinergy Canada, Inc. from 2003 to 2005 and President of Bear Paw Energy, LLC, a subsidiary of Northern Border Partners, L.P., from 2000 to 2002. He also held various positions with Enron Corporation, The Williams Companies, Inc., Apache Corporation and ConocoPhillips. He received a B.S. in Civil Engineering from the University of Arizona. We believe that Mr. Bierbach s experience as President and Chief Executive Officer of our general partner and related familiarity with our assets as well as his extensive knowledge of the midstream natural gas industry provide him with the necessary skills to be a member of the board of directors of our general partner.

Sandra M. Flower has served as Vice President of Finance of our general partner since November 2009. Ms. Flower also served as our Controller from November 2009 until March 2011. Prior to our formation, Ms. Flower served as Group Controller at TransMontaigne, Inc. and as Director of Internal Audit for TransMontaigne Partners, LP from 2005 to 2009. While at TransMontaigne, she was responsible for trading support, credit, accounting and consolidation activities of TransMontaigne Inc., as well as supervising the design and implementation of all internal audit activities including Sarbanes-Oxley compliance procedures. Ms. Flower began her career at Touche Ross & Co. She received a B.S.B.A. from the University of Rhode Island and is a CPA.

John J. Connor II has served as Senior Vice President of Operations and Engineering of our general partner since November 2009. Prior to our formation, Mr. Connor served as Vice President of Development at Foothills Energy Ventures, LLC. Prior to Foothills, he was Director of Midstream Operations at Black Hills Midstream, LLC from 2006 to 2007 and held various Director and General Manager positions at El Paso Corporation from 1980 to 2004. Mr. Connor received his B.S. in Civil Engineering from Colorado State University and is a licensed professional engineer.

Marty W. Patterson has served as Senior Vice President of Commercial Services of our general partner since November 2009. Prior to our formation, he served as Vice President of Commercial Operations at Foothills Energy Ventures, LLC from 2006 to 2009. Prior to joining Foothills, Mr. Patterson was the Director of Commercial Operations with Cinergy Corp. from 2004 to 2006. Before that, he was the Senior VP Energy Services, IDACORP Energy, L.P. from 1997 to 2003, and held various other positions, focused on operations. Mr. Patterson received his degree in Petroleum Technology from Kilgore College and is currently a board member of the North American Energy Standards Board.

William B. Mathews has served as Secretary and Vice President of Legal Affairs of our general partner since November 2009 and General Counsel of our general partner since March 2011. Prior to our formation, he served as Vice President, General Counsel and Secretary of Foothills Energy Ventures, LLC from December 2006 to November 2009, as well as a director from August 2009 to November 2009. Prior to Foothills, Mr. Mathews served as Assistant General Counsel for ONEOK Partners, L.P., Northern Border Partners, L.P. and Bear Paw Energy, LLC from July 2001 to December 2006 and, previous to that, as Vice President and General Counsel of Duke Energy Field Services (now DCP Midstream, LLC) until 2000, having joined a predecessor company in 1985. He received a J.D. from the University of Denver and a B.S. in Civil Engineering from the University of Colorado.

Eileen A. Aptman was elected as a member of the board of directors of our general partner in September 2011. Since 2002, Ms. Aptman has been the Chief Investment Officer for Belfer Management LLC, a family investment firm located in New York City and an active investor in all aspects of the global capital markets. Prior to joining Belfer Management in 2002, Ms. Aptman managed the small and midcap value investment strategy in the asset management division of Goldman Sachs. Ms. Aptman holds a BA from Tufts University in Political Science and Asian Studies and is a Chartered Financial Analyst.

Matthew P. Carbone was elected as a member of the board of directors of our general partner in November 2009. Mr. Carbone has been a Managing Director of AIM since he co-founded AIM in July 2006. Prior to co-founding AIM, from January 2005 until July 2006, Mr. Carbone was a Managing Director of McCown De Leeuw & Co., or MDC. Mr. Carbone has spent nearly 20 years in private equity and investment banking. Prior to MDC he led Wit Capital Group s West Coast operations and worked in the investment banking divisions of Morgan Stanley, First Boston Corporation and Smith Barney. Mr. Carbone is also a member of the board of directors of the general partner of Oxford Resource Partners L.P. He received an MBA from Harvard Business School and a B.A. in Neuroscience from Amherst College. We believe that Mr. Carbone s nearly 20 years of experience in corporate finance, as well as his in-depth knowledge of the midstream natural gas industry generally and our partnership in particular, provide him with the necessary skills to be a member of the board of directors of our general partner.

Edward O. Diffendal was elected as a member of the board of directors of our general partner in November 2009. Mr. Diffendal joined AIM in September 2007 as a Principal. Prior to joining AIM he served as a management consultant from 2005 to 2007, held various operating positions at Veritas Software Corp. from 2003 to 2005, was a Vice President at Broadview Capital Partners, L.P. from 2000 to 2003 and was a consultant at Monitor Company from 1991 to 1998. Mr. Diffendal received an MBA from Dartmouth College and M.A. and B.A. degrees in Economics from Stanford University. We believe that Mr. Diffendal s over 10 years of experience in corporate finance, as well as his in-depth knowledge of the midstream natural gas industry generally and our partnership in particular, provide him with the necessary skills to be a member of the board of directors of our general partner.

David L. Page was elected as a member of the board of directors of our general partner in February 2010. Mr. Page also serves as Chairman of the Executive Committee of our General Partner. Mr. Page has served as a management consultant since February 2002. Prior to working as a management consultant, Mr. Page served as Chairman and Chief Executive Officer of Distribution Dynamics, Inc. from January 2000 until February 2002. His earlier career included a variety of management roles at McCown De Leeuw & Co. from 1994 through 2000. Prior to joining McCown De Leeuw & Co., Mr. Page was President and Chief Executive Officer of Page Packaging Corporation from 1987 through 1993, and Vice President and General Manager of Boise Cascade Corporation from 1959 through 1987. Mr. Page received a B.A. in Business Administration and Economics from Whitman College and completed the Executive Program at Stanford University. We believe that Mr. Page s over 20 years of operating experience, as well as his in-depth knowledge of our partnership, provide him with the necessary skills to be a member of the board of directors of our general partner

L. Kent Moore was elected as a member of the board of directors of our general partner in November 2009. Mr. Moore owns Eagle River Ventures, LLC, which holds mostly oil and gas investments and a 0.5% interest in AIM Midstream Holdings. From 2006 through 2011, Mr. Moore served as chairman of the board of directors of Foothills Energy Ventures, LLC. He also serves as chairman of the board of trustees for the Old Mutual Funds I and II. He has also served as a portfolio manager and vice-president at Janus Capital, and as analyst/portfolio manager for Marsico Capital Management, focusing on technology and energy stocks. Before working in the mutual fund industry, Mr. Moore was a vice-president with Exeter Drilling Company and also co-founded and was President of Caza Drilling Company. Mr. Moore received a B.S. in Industrial Management from Purdue University. We believe that Mr. Moore s over 20 years of investing and operating experience, as well as his in-depth knowledge of the midstream natural gas industry generally and our partnership in particular, provide him with the necessary skills to be a member of the board of directors of our general partner.

Gerald A. Tywoniuk was elected as a member of the board of directors of our general partner in May 2011. In July 2011, he became a part-time Senior Consultant to the Chief Financial Officer of CIBER, Inc., a global information technology services company. Prior thereto, from May 2010 to July 2011, Mr. Tywoniuk served as interim Senior Vice President, Finance of CIBER, Inc. Mr. Tywoniuk continues to act on a part-time consulting basis as the Plan Representative for the plan of liquidation of Pacific Energy Resources Ltd., which was an oil and gas acquisition, exploitation and development company and is now completing its plan of liquidation. Mr. Tywoniuk joined Pacific Energy Resources Ltd. in June 2008 as Senior Vice President, Finance and he was appointed Chief Financial Officer in August 2008. He was also appointed acting Chief Executive Officer in September 2009. He held these positions as an employee until May 2010. Mr. Tywoniuk joined Pacific Energy Resources Ltd. in June 2008 to help the management team work through the company s financially distressed situation. The board of the company elected to file for Chapter 11 protection in March 2009. In December 2009, the company completed the sale of its assets, and is now working through the remaining steps of liquidation. Prior to joining Pacific Energy Resources Ltd., Mr. Tywoniuk acted as an independent consultant in accounting and finance from March 2007 to June 2008. From December 2002 through November 2006, Mr. Tywoniuk was Senior Vice President and Chief Financial Officer of Pacific Energy Partners, LP. From November 2006 to March 2007, Mr. Tywoniuk assisted with the integration of Pacific Energy Partners, LP after it was acquired by Plains All American Pipeline, L.P. Mr. Tywoniuk holds a Bachelor of Commerce degree from The University of Alberta, Canada, and is a Canadian chartered accountant. He currently serves as a director and audit committee chairperson on the board of the general partner of Oxford Resource Partners, LP (NYSE:OXF). Mr. Tywoniuk has 30 years of experience in accounting and finance, including 12 years as the Chief Financial Officer of three public companies and 4 years as Vice President/Controller of a fourth public company. Mr. Tywoniuk s extensive accounting, financial and executive management experience and his prior experience with publicly traded partnerships, provide him with the necessary skills to be a member of the board of directors of our general partner and a member and the chairman of the Audit Committee. With respect to the Audit Committee, he also qualifies as an audit committee financial expert.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner s board of directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10 percent unitholders are required by the SEC s regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our general partner s officers, directors and greater than 10 percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2011, except as disclosed below.

Eileen A. Aptman failed to timely file one Initial Statement of Beneficial Ownership of Securities on Form 3 upon her appointment as a director of our general partner. Ms. Aptman filed the Form 3 on October 10, 2011.

Item 11 Executive Compensation

Our general partner, under the direction of its board of directors, or the Board, is responsible for managing our operations and employs all of the employees that operate our business. The compensation payable to the officers of our general partner is paid by our general partner and such payments are reimbursed by us on a dollar-for-dollar basis.

The following is a discussion of the compensation policies and decisions of the Compensation Committee of the Board, with respect to the following individuals, who are executive officers of our general partner and referred to as the named executive officers for the fiscal years ended December 31, 2011 and 2010:

- Brian F. Bierbach, President and Chief Executive Officer;
- Sandra M. Flower, Vice President of Finance;
- John J. Connor II, Senior Vice President of Operations and Engineering;
- Marty W. Patterson, Senior Vice President of Commercial Services; and
- William B. Mathews, Secretary, General Counsel and Vice President of Legal Affairs

Our compensation program is designed to recruit and retain as executive officers individuals with the highest capacity to develop, grow and manage our business, and to align their compensation with our short-term and long-term goals. To do this, our compensation program for executive officers is made up of the following main components: (i) base salary, designed to compensate our executive officers for work performed during the fiscal year; (ii) short-term incentive programs, designed to reward our executive officers for our yearly performance and for their individual performances during the fiscal year; and (iii) equity-based awards, meant to align our executive officers interests with our long-term performance.

This section should be read together with the compensation tables that follow, which disclose the compensation awarded to, earned by or paid to the named executive officers with respect to the years ended December 31, 2011 and 2010.

Role of the Board, the Compensation Committee and Management

The Board has appointed the Compensation Committee to assist the Board in discharging its responsibilities relating to compensation matters, including matters relating to compensation programs for directors and executive officers of the general partner. The Compensation Committee has overall responsibility for evaluating and approving our compensation plans, policies and programs, setting the compensation and benefits of executive officers, and granting awards under and administering our equity compensation plans. The Compensation Committee is charged with, among other things, establishing compensation practices and programs that are (i) designed to attract, retain and motivate exceptional leaders, (ii) structured to align compensation with our overall performance and growth in distributions to unitholders, (iii) implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans, and (iv) applied to reward performance.

As described in further detail below under Elements of the Compensation Programs, the compensation programs for our executive officers consist of base salaries, annual incentive bonuses and awards under the American Midstream GP, LLC Long-Term Incentive Plan, which we refer to as our LTIP, currently in the form of equity-based phantom units, as well as other customary employment benefits such as a 401(k) plan and health and welfare benefits. We expect that total compensation of our executive officers and the components and allocation among components of their annual compensation will be reviewed on at least an annual basis by the Compensation Committee.

During 2011 and 2010, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2012 and in future years. Topics discussed and to be discussed at these meetings included and will include, among other things, (i) assessing the performance of the Chief Executive Officer, or the CEO, and other executive officers with respect to our results for the prior year, (ii) reviewing and assessing the personal performance of the executive officers for the preceding year and (iii) determining the amount of the bonus pool to be paid to our executive officers for a given year after taking into account the target bonus amounts established for those executive officers at the outset of the year. In addition, at these meetings, and after taking into account the recommendations of our CEO only with respect to executive officers other than our CEO, base salary levels and target bonus amounts (representing the bonus that may be awarded expressed as a dollar amount or as a percentage of base salary for the year) for all of our executive officers will be established by the Compensation Committee. In addition, the Compensation Committee will make its decisions with respect to any awards under the LTIP. We expect that our CEO will provide periodic recommendations to the Compensation Committee regarding the performance and compensation of the other named executive officers.

Compensation Objectives and Methodology

The principal objective of our executive compensation program is to attract and retain individuals of demonstrated competence, experience and leadership who share our business aspirations, values, ethics and culture. A further objective is to provide incentives to and reward our executive officers and other key employees for positive contributions to our business and operations, and to align their interests with our unitholders interests.

In setting our compensation programs, we consider the following objectives:

- to create unitholder value through sustainable earnings and cash available for distribution;
- to provide a significant percentage of total compensation that is at-risk or variable;
- to encourage significant equity holdings to align the interests of executive officers and other key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation and executive compensation.

Taking account of the foregoing objectives, we structure total compensation for our executives to provide a guaranteed amount of cash compensation in the form of competitive base salaries, while also providing a meaningful amount of annual cash compensation that is at risk and dependent on our performance and individual performances of the executives, in the form of discretionary annual bonuses. We also seek to provide a portion of total compensation in the form of equity-based awards under our LTIP, in order to align the interests of executives and other key employees with those of our unitholders and for retention purposes. Historically, we have not made regular annual grants of awards under our LTIP. To date, the only awards under our LTIP were made in connection with our formation, although certain of these grants were made in 2010. Going forward, we expect that equity-based awards will be made more regularly and that equity-based awards will become more prominent in our annual compensation decision-making process.

Compensation decisions for individual executive officers are the result of the subjective analysis of a number of factors, including the individual executive officer s experience, skills or tenure with us and changes to the individual executive officer s position. In evaluating the contributions of executive officers and our performance, although no pre-determined numerical goals were established, a variety of financial measures have been generally considered, including non-GAAP financial measures used by management to assess our financial performance, such as adjusted EBITDA and cash available for distribution. For a definition of adjusted EBITDA, please read For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read Management s Discussion and Analysis How We Evaluate Our Operations . In addition, a variety of factors related to the individual performance of the executive officer were taken into consideration.

In making individual compensation decisions, the Compensation Committee historically has not relied on pre-determined performance goals or targets. Instead, determinations regarding compensation have been the result of the exercise of judgment based on all reasonably available information and, to that extent, were discretionary. Each executive officer s current and prior compensation is considered in setting future compensation. The amount of each executive officer s current compensation will be considered as a base against which determinations are made as to whether increases are appropriate to retain the executive officer in light of competition or in order to provide continuing performance incentives. Subject to the provisions contained in the executive officer s employment agreement, if any, the Compensation Committee has discretion to adjust any of the components of compensation to achieve our goal of recruiting, promoting and retaining as executive officers, individuals with the skills necessary to execute our business strategy and develop, grow and manage our business.

To date, we have not reviewed executive compensation against a specific group of comparable companies or publicly traded partnerships. Rather, the Compensation Committee has historically relied upon the judgment and industry experience of its members in making decisions with respect to total compensation and with respect to the allocation of total compensation among our three main components of compensation. Going forward, we expect that the Compensation Committee will make compensation decisions taking into account trends occurring within our industry, including from a peer group of companies, which we expect will include the following similar publicly traded partnerships: Boardwalk Pipeline Partners, LP, Regency Energy Partners LP, Targa Resources Partners LP, MarkWest Energy Partners LP, Copano Energy LLC, Crosstex Energy LP, and Atlas Pipeline Partners LP. Additionally, we expect that the Compensation Committee will take into account trends occurring within a group of publicly traded energy companies with market capitalizations in the same range as our own, including from a peer group of companies, which we expect will include the following similar publicly-traded energy companies: Contango Oil & Gas Co., Goodrich Petroleum Corp., Kodiak Oil & Gas Corp., Magnum Hunter Resources Corp., Penn Virginia Corp., Resolute EnergyCorporation, Approach Resources, Inc., PetroQuest Energy Inc. and Rex Energy Corporation. To date, the Compensation Committee has not retained the services of any compensation consultants.

Elements of the Compensation Programs

Overall, the executive officer compensation programs are designed to be consistent with the philosophy and objectives set forth above. The principal elements of our executive officer compensation programs are summarized in the table below, followed by a more detailed discussion of each compensation element.

Element	Characteristics	Purpose
Base Salaries	Fixed annual cash compensation. Executive officers are eligible for periodic increases in base salaries. Increases may be based on performance or such other factors as the Compensation Committee may determine.	Keep our annual compensation competitive with the defined market for skills and experience necessary to execute our business strategy.
Annual Incentive Bonuses	Performance-related annual cash incentives earned based on our objectives and individual performance of the executive officers. We expect that trends for our peer group will be taken into account in setting future annual cash incentive awards for our executive officers.	Align performance to our objectives that drive our business and reward executive officers for our yearly performance and for their individual performances during the fiscal year.
Equity-Based Awards (Phantom-units and Distribution Equivalent Rights)	Performance-related, equity-based awards granted at the discretion of the Compensation Committee. Awards are based on our performance and we expect that, going forward, will take into account competitive practices at peer companies. Grants typically consist of phantom units that vest ratably over four years and may be settled upon vesting with either a net cash payment or an issuance of common units, at the discretion of the Board. Historically, the Board has issued common units upon vesting of phantom units. Distribution Equivalent Rights, or DERs, which have been granted in conjunction with such phantom unit awards, entitle the grantee to receive cash distributions on unvested LTIP awards to the same extent generally as unitholders receive cash distributions on our common units.	Align interests of executive officers with unitholders and motivate and reward executive officers to increase unitholder value over the long term. Ratable vesting over a four-year period is designed to facilitate retention of executive officers. Issuance of common units upon vesting encourages equity ownership in order to align interests of executive officers with those of unitholders. DERs provide a clear, objective link between growing distributions to unitholders and executive compensation. (1)
Retirement Plan	Qualified retirement plan benefits are available for our executive officers and all other regular full-time employees. At our formation, we adopted and are maintaining a tax-deferred or after-tax 401(k) plan in which all eligible employees can elect to defer compensation for retirement up to IRS imposed limits. The 401(k) plan permits us to make annual discretionary matching contributions to the plan. For 2010, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% of the employee s eligible compensation.	Provide our executive officers and other employees with the opportunity to save for their future retirement.
Health and Welfare Benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for our executive officers and all other regular full-time employees.	Provide benefits to meet the health and wellness needs of our executive officers and other employees and their families.

(1) On June 9, 2011, we amended each of the outstanding phantom unit grant agreements with our named executive officers to eliminate the DERs previously granted with our phantom units in exchange for a one-time aggregate payment of approximately $1.0 million. We do not expect to use grants of DERs as an element of our compensation programs in the future.

Base Salaries

Base salaries for our executive officers will be determined annually by an assessment of our overall financial and operating performance, each executive officer s performance evaluation and changes in executive officer responsibilities. While many aspects of performance can be measured in financial terms, senior management will also be evaluated in areas of performance that are more subjective. These areas include the development and execution of strategic plans, the exercise of leadership in the development of management and other employees, innovation and improvement in our business activities and each executive officer s involvement in industry groups and in the communities that we serve. We seek to compensate executive officers for their performance throughout the year with annual base salaries that are fair and competitive within our marketplace. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions and with similar responsibilities in our marketplace and adjusted for financial and operating performance and each executive officer s performance evaluation, length of service with us and previous work experience. Individual salaries have historically been established by the Compensation Committee based on the general industry knowledge and experience of its members, in alignment with these considerations, to ensure the attraction, development and retention of superior talent. Going forward, we expect that determinations will continue to focus on the above considerations and will also take into account relevant market data, including data from our peer group.

We expect that base salaries will be reviewed annually to ensure continuing consistency with market levels and our level of financial performance during the previous year. Future adjustments to base salaries and salary ranges will reflect movement in the competitive market as well as individual performance. Annual base salary adjustments, if any, for the CEO will be determined by the Compensation Committee. Annual base salary adjustments, if any, for the other executive officers will be determined by the Compensation Committee, taking into account input from the CEO.

On June 9, 2011, we entered into new employment agreements with each of our named executive officers, which agreements were effective upon the completion of our initial public offering. In connection with approving the new employment agreements, the Compensation Committee approved base salary increases for 2011 for the named executive officers as provided in the table below.

Name	Base Salary at the beginning of 2011	Base Salary Increase	New Base Salary Post IPO
Brian F. Bierbach	$ 235,000	$ 40,000	$ 275,000
Sandra M. Flower	$ 140,000	$ 35,000	$ 175,000
Marty W. Patterson	$ 190,000	$ 30,000	$ 220,000
John J. Connor II	$ 185,000	$ 35,000	$ 220,000
William B. Mathews	$ 185,000	$ 30,000	$ 215,000

Annual Incentive Bonuses

As one way of accomplishing compensation objectives, executive officers are rewarded for their contribution to our financial and operational success through the award of discretionary annual cash incentive bonuses. Annual cash incentive awards, if any, for the CEO are determined by the Compensation Committee. Annual cash incentive awards, if any, for the other executive officers are determined by the Compensation Committee taking into account input from the CEO.

We expect to review annual cash bonus awards for the named executive officers annually to determine award payments for the prior fiscal year, as well as to establish target bonus amounts for the current fiscal year. At the beginning of each year, the Compensation Committee meets with the CEO to discuss partnership and individual goals for the year and what each executive is expected to contribute in order to help the partnership achieve those goals. However, the amounts of the annual bonuses have been determined in the discretion of the Compensation Committee.

While target bonuses for our executive officers who have entered into employment agreements have been initially set at dollar amounts that are 25% to 100% of their base salaries, the Compensation Committee has had broad discretion to retain, reduce or increase the award amounts when making its final bonus determinations. Bonuses (similar to other elements of the compensation provided to executive officers) historically have not been solely based on a prescribed formula or pre-determined goals or specified performance targets but rather have been determined on a discretionary basis and generally have been based on a subjective evaluation of individual, company-wide and industry performances. Target bonus amounts for 2011 for all of the executive officers, which are specified in their new employment agreements, are set forth in the table below. Please refer to New Employment Agreements with Named Executive Officers below for a description of the new employment agreements.

The Board and the Compensation Committee believed that this approach to assessing performance resulted in a more comprehensive evaluation for compensation decisions. In 2010, the Compensation Committee recognized the following factors in making discretionary annual bonus recommendations and determinations:

- a subjective performance evaluation based on company-wide financial and individual qualitative performance, as determined in the Compensation Committee s discretion; and
- the scope, level of expertise and experience required for the executive officer s position.

These factors were selected as the most appropriate measures upon which to base the annual incentive cash bonus decisions because our Compensation Committee believed that they help to align individual compensation with performance and contribution. With respect to its evaluation of company-wide financial performance, although no pre-determined numerical goals are established, the Compensation Committee generally reviewed our results with respect to adjusted EBITDA and cash available for distribution in making annual bonus determinations.

Following its performance assessment, and based on our financial performance with respect to these criteria and the Compensation Committee s qualitative assessment of individual performance, the Compensation Committee determined to award the incentive bonus amounts set forth in the table below to our named executive officers for performance in 2010.

Name	2010 Target Bonus	2010 Bonus Awards
Brian F. Bierbach	$ 65,000	$ 65,000
Sandra M. Flower	N/A	$ 35,000
Marty W. Patterson	$ 35,000	$ 35,000
John J. Connor II	$ 40,000	$ 50,000
William B. Mathews	N/A	$ 35,000

Bonus amounts were awarded based on our financial performance with respect to these criteria and the Compensation Committee s qualitative assessment of individual performance. Mr. Connor was awarded in excess of his target bonus in recognition of exceptional performance in the areas of control of operational costs and execution of capital projects.

Beginning in 2011, the Compensation Committee expects that it will base annual incentive compensation award recommendations on additional company-wide criteria as well as industry criteria, recognizing the following factors as part of its determination of annual incentive bonuses (without assigning any particular weighting to any factor):

- financial performance for the prior fiscal year, including adjusted EBITDA and cash available for distribution;
- distribution performance for the prior fiscal year compared to the peer group;
- unitholder total return for the prior fiscal year compared to the peer group; and
- competitive compensation data of executive officers in the peer group.

These factors were selected as the most appropriate measures upon which to base the annual cash incentive bonus decisions going forward because the Compensation Committee believes that they will most directly correlate to increases in long-term value for our unitholders.

In June 2011, the Compensation Committee established the 2011 target bonus amounts for the named executive officers as provided in the table below.

Name	2010 Target Bonus	Target Bonus Increase	2011 Target Bonus	2011 Bonus Awards
Brian F. Bierbach	$ 65,000	$ 210,000	$ 275,000	$ 220,000
Sandra M. Flower	N/A	N/A	$ 100,000	$ 82,000
Marty W. Patterson	$ 35,000	$ 95,000	$ 130,000	$ 103,000
John J. Connor II	$ 40,000	$ 90,000	$ 130,000	$ 103,000
William B. Mathews	N/A	N/A	$ 100,000	$ 91,000

Equity-Based Awards

Design. The LTIP was adopted in 2009 in connection with our formation. In adopting the LTIP, the Board recognized that it needed a source of equity to attract new members to and retain members of the management team, as well as to provide an equity incentive to other key employees and non-employee directors. We believe the LTIP promotes a long-term focus on results and aligns executive and unitholder interests. Historically, we have granted phantom units with associated DERs to provide long-term incentives to our named executive officers. DERs enable the recipients of phantom unit awards to receive cash distributions on our phantom units to the same extent generally as unitholders receive cash distributions on our common units. In June 2011, existing LTIP grant agreements with the named executive officers and certain board members were modified to exclude the DER provision in exchange for a cash payment of $1.3 million.

The LTIP is designed to encourage responsible and profitable growth while taking into account non-routine factors that may be integral to our success. Long-term incentive compensation in the form of equity grants are used to provide incentives for performance that leads to enhanced unitholdervalue, encourage retention and closely align the executive officers interests with unitholders interests. Equity grants provide a vital link between the long-term results achieved for our unitholders and the rewards provided to executive officers and other key employees.

Phantom Units. The only awards made under the LTIP since its adoption have been phantom units. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Historically, our Board has always issued common units instead of cash. Unless an individual award agreement provides otherwise, the LTIP provides that unvested phantom units are forfeited at the time the holder terminates employment or board membership, as applicable. The terms of the award agreements of our named executive officers provide that a termination due to death or disability results in full acceleration of vesting. In general, phantom units awarded under our LTIP vest as to 25% of the award on each of the first four anniversaries of the date of grant. A grant of phantom units may include accompanying DERs, which entitle the grantee to receive a cash payment with respect to each phantom unit equal to the cash distribution made by the partnership on each common unit. Currently outstanding awards are phantom units without DER s.

Equity-Based Award Policies. Prior to 2011, equity-based awards were granted by the Compensation Committee in connection with our formation. Going forward, we expect that equity-based awards will be awarded by the Compensation Committee on an annual basis as part of the ongoing total annual compensation package for executive officers. No named executive officers received any awards under the LTIP in 2011. On March 2, 2010, Ms. Flower and Mr. Mathews received split adjusted awards of 25,034 phantom units and 12,517 phantom units (after giving effect to the reverse unit split as part of the recapitalization which occurred prior to our initial public offering), respectively, including accompanying DERs, in connection with our formation. No other named executive officers received any awards under the LTIP in 2010.

Deferred Compensation

Tax-qualified retirement plans are a common way that companies assist employees in preparing for retirement. We provide our eligible executive officers and other employees with an opportunity to save for their retirement by participating in our 401(k) savings plan. The 401(k) plan allows executive officers and other employees to defer compensation (up to IRS imposed limits) for retirement and permits us to make annual discretionary matching contributions to the plan. For 2010, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% of the employee s eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation.

Other Benefits

Each of the named executive officers is eligible to participate in our employee benefit plans which provide for medical, dental, vision, disability insurance and life insurance benefits, which are provided on the same terms as available generally to all salaried employees. In 2011 and 2010, no perquisites were provided to the named executive officers.

Recoupment Policy

We currently do not have a recoupment policy applicable to annual incentive bonuses or equity awards. The Compensation Committee expects to continue to evaluate the need to adopt such a policy, in light of current legislative policies as well as economic and market conditions.

Employment and Severance Arrangements

The Board and the Compensation Committee consider the maintenance of a sound management team to be essential to protecting and enhancing our best interests. To that end, we recognize that the uncertainty that may exist among management with respect to their at-will employment with our general partner may result in the departure or distraction of management personnel to our detriment. Accordingly, our general partner previously entered into employment agreements with each of Messrs. Bierbach, Patterson and Connor, which existing employment agreements contain severance arrangements that we believed were appropriate to encourage the continued attention and dedication of members of our management. These employment agreements are described more fully below under Existing Employment Agreements with Named Executive Officers. In connection with the initial public offering, on June 9, 2011, our general partner entered into new employment agreements with each of our named executive officers to be effective upon the closing of the offering. These new employment agreements are described more fully under New Employment Agreements with Named Executive Officers below.

Summary Compensation Table for 2011 and 2010

The following table sets forth certain information with respect to the compensation paid to the named executive officers for the years ended December 31, 2011 and 2010.

	Year	Salary	Bonus	Unit Awards (a)	All Other Compensation (b)	Total Compensation
Brian F. Bierbach	2011	$ 251,615	$ 220,000	$	$ 478,870	$ 950,485
President and Chief Executive Officer	2010	235,000	65,000		183,016	483,016
Sandra M. Flower	2011	154,539	82,000		172,852	409,391
Vice President of Finance	2010	140,000	35,000	643,691	7,437	826,128
Marty W. Patterson	2011	202,462	103,000		240,476	545,938
Senior Vice President of Commercial Services	2010	190,000	35,000		91,733	316,733
John J. Connor II	2011	199,538	103,000		240,476	543,014
Senior Vice President of Operations and Engineering	2010	185,000	50,000		91,717	326,717
William B. Mathews	2011	198,361	91,000		93,561	382,922
Vice President Legal Affairs, General Counsel and Secretary	2010	185,000	35,000	321,839	9,872	551,711

(a) Amounts shown in this column do not reflect dollar amounts actually received by our named executive officers. Instead, these amounts reflect the aggregate grant date fair value of each phantom unit award granted in the year ended December 31, 2010 computed in accordance with the provisions of Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation Stock Compensation (FASB ASC Topic 718). Assumptions used in the calculation of these amounts are included in Note 14 to our audited consolidated financial statements included in this Form 10-K.

(b) Amounts shown in this column include employer contributions to the named executive officers 401(k) plan accounts and life insurance premiums paid by the employer. In addition, the table setforth below represents the dollar value of distributions paid on phantom unit awards pursuant to the DER s including a one-time payment on June 9, 2011 in consideration for the elimination of the DER s previously granted. The amounts of such distributions pursuant to DERs are not included in the 2010 amounts shown for Ms. Flower and Mr. Mathews because the grant date fair value of their awards reported in the Unit Awards column factors in the value of such distributions pursuant to the DERs.

	2011	2010
Brian F. Bierbach	$ 476,784	$ 182,283
Sandra M. Flower	163,118	N/A
Marty W. Patterson	238,390	91,140
John J. Connor II	238,390	N/A
William B. Mathews	81,557	91,140

Grants of Plan-Based Awards for 2011

No named executive officers received any awards under the LTIP in 2011.

Employment Agreements with Named Executive Officers

In June 2011, our general partner entered into new employment agreements with each of our named executive officers, which became effective as of the closing of our initial public offering. Each of the employment agreements has an initial term of two years, which will be automatically extended for successive one year terms until either party elects to terminate the agreement by giving written notice at least 90 days prior to the end of the expiration of the initial or extended term, as applicable. The base salary and target bonus amounts set forth in such employment agreements are shown in the table below. The employment agreements provide that the base salary may be increased but not decreased (except for a decrease that is consistent with reductions taken generally by other executives of the general partner). The agreements provide that the executive will be provided with the opportunity to earn an annual cash bonus, 20 percent of which will be conditioned and determined on the attainment of personal performance goals and 80 percent of which will be conditioned and determined on the attainment of organizational performance goals, in each case as set by, and based on performance criteria established by, the Compensation Committee. The employment agreements also provide that the executive is eligible to receive awards under the LTIP as determined by the Compensation Committee.

Name	2011 Base Salary	2011 Target Bonus
Brian F. Bierbach	$ 275,000	$ 275,000

Sandra M. Flower	$ 175,000	$ 100,000
Marty W. Patterson	$ 220,000	$ 130,000
John J. Connor II	$ 220,000	$ 130,000
William B. Mathews	$ 215,000	$ 100,000

Each employment agreement also contains certain confidentiality covenants prohibiting each executive officer from, among other things, disclosing confidential information relating to our general partner or any of its affiliates, including us. The employment agreements also contain non-competition and non-solicitation restrictions, which apply during the term of the executive s employment with our general partner and, with certain exceptions, continue for a period of 12 months following termination for any reason.

The employment agreements also provide for, among other things, the payment of severance benefits under certain circumstances. Please refer to Potential Payment Upon Termination or Change in Control Employment Agreements with Named Executive Officers below for a description of these benefits under the new employment agreements.

Outstanding Equity-Based Awards at December 31, 2011

The following table provides information regarding outstanding split adjusted equity-based awards held by the named executive officers as of December 31, 2011. All such equity-based awards consist of phantom units granted under the LTIP.

	Unit Awards	
Name	Number of Phantom Units that Have Not Vested (a)	Market Value of Phantom Units that Have Not Vested (b)
Brian F. Bierbach	37,551	$ 682,302
Sandra M. Flower	18,775	$ 341,142
Marty W. Patterson	18,775	$ 341,142
John J. Connor II	18,775	$ 341,142
William B. Mathews	9,387	$ 170,562

(a) The awards to Messrs. Bierbach, Patterson and Connor were granted on November 2, 2009. The awards to Ms. Flower and Mr. Mathews were awarded on March 2, 2010. Each of the awards vests as to 25% of the award on each of the first four anniversaries of the date of grant.

(b) The market value of phantom units that had not vested as of December 31, 2010 is calculated based on the fair market value of our common units as of December 31, 2011, which was $18.17 multiplied by the number of unvested phantom units. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Equity-Based Awards.

Units Vested in 2011 and 2010

The following table shows the split adjusted phantom unit awards that vested during 2011 and 2010.

	2011			2010		
Name	Number of Units Acquired on Vesting	Fair Market Value per Unit Upon Vesting	Value Realized on Vesting (a)	Number of Units Acquired on Vesting	Fair Market Value per Unit Upon Vesting	Value Realized on Vesting (a)
Brian F. Bierbach	18,775	$ 17.79	$ 334,007	18,775	$ 20.60	$ 386,840
Sandra M. Flower	6,258	$ 20.60	$ 128,947		N/A	$
Marty W. Patterson	9,388	$ 17.79	$ 167,013	9,388	$ 20.60	$ 193,420
John J. Connor II	9,388	$ 17.79	$ 167,013	9,388	$ 20.60	$ 193,420
William B. Mathews	3,129	$ 20.60	$ 64,473		N/A	$

(a) The value realized upon vesting of phantom units is calculated based on the fair market value of our common units at the applicable vesting date.

Long-Term Incentive Plan

The Board has adopted our LTIP for employees, consultants and directors of our general partner and affiliates who perform services for us. The plan provides for the issuance of options, unit appreciation rights, restricted units, phantom units, other unit-based awards, unit awards or replacement awards, as well as tandem DERs granted with respect to an award. To date, only phantom units some with DERs, have been issued under the LTIP. Currently, outstanding awards are phantom units without DER s.

March 12, 2012, 142,552 unvested phantom units are outstanding under our LTIP. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Historically, our Board has always issued common units in lieu of cash upon vesting of a phantom unit. DERs may be granted in tandem with phantom units. Except as otherwise provided in an award agreement, DERs that are not subject to a restricted period are currently paid to the participant at the time a distribution is made to the unitholders, and DERs that are subject to a restricted period are paid to the participant in a single lump sum no later than the 15th day of the third calendar month following the date on which the restricted period ends.

The number of units that may be delivered with respect to awards under the LTIP may not exceed 303,601 units, subject to specified anti-dilution adjustments. However, if any award is terminated, cancelled, forfeited or expires for any reason without the actual delivery of units covered by such award or units are withheld from an award to satisfy the exercise price or the employer s tax withholding obligation with respect to such award, such units will again be available for issuance pursuant to other awards granted under the LTIP. In addition, any units allocated to an award will, to the extent such award is paid in cash, be again available for delivery under the LTIP with respect to other awards. There is no limitation on the number of awards that may be granted under the LTIP and paid in cash. The LTIP provides that it is to be administered by the Board, provided that the Board may delegate authority to administer the LTIP to a committee of non-employee directors. As of February 29, 2012, there are 54,827 units available for furure grant awards.

The LTIP may be terminated or amended at any time, including increasing the number of units that may be granted, subject to unitholder approval as required by the securities exchange on which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant. The plan will terminate on the earliest of (i) its termination by the Board or the Compensation Committee, (ii) the tenth anniversary of the date the LTIP was adopted or (iii) when units are no longer available for delivery pursuant to awards under the LTIP. Unless expressly provided for in the plan or an applicable award agreement, any award granted prior to the termination of the plan, and the authority of the Board or the Compensation Committee to amend, adjust or terminate such award or to waive any conditions or rights under such award, will extend beyond the termination date.

Potential Payments Upon Termination or Change in Control

Employment Agreements with Named Executive Officers

The employment agreements provide for, among other things, the payment of severance benefits following certain terminations of employment by our general partner, the termination of employment for Good Reason (as defined below) by the executive officer, or, under certain circumstances, upon expiration of the term of the agreement. Under the employment agreements, if the executive s employment is terminated upon expiration of the initial or extended term of the agreement by either party upon 90 days written notice (with certain exceptions, as described below), if the executive s employment is terminated by the general partner other than for Cause (defined as defined below) or other than upon the executive s death or disability, or if the executive resigns for Good Reason, the executive will have the right to severance in an amount equal to the sum of the executive s annual base salary at the rate in effect on the date of termination plus the amount, if any, paid to the executive as an annual cash bonus for the calendar year ending immediately prior to the date of such termination. Such severance amount will be paid in installments (on regular pay days scheduled in accordance with our regular payroll practices) beginning on the 60th day following the termination date and ending on the one year anniversary of the termination date, and will be subject to reimbursement by us to our general partner. The foregoing severance benefit is conditioned on the executive executing a release of claims in favor of our general partner and its affiliates, including us.

Cause : defined in each of the employment agreements as the executive having (i) engaged in gross negligence, gross incompetence or willful misconduct in the performance of the duties required of him under the employment agreement, (ii) refused without proper reason to perform the duties and responsibilities required of him under the employment agreement, (iii) willfully engaged in conduct that is materially injurious to our general partner or its affiliates including us (monetarily or otherwise), (iv) committed an act of fraud, embezzlement or willful breach of fiduciary duty to our general partner or an affiliate including us (including the unauthorized disclosure of confidential or proprietary material information of our general partner or an affiliate including us) or (v) been convicted of (or pleaded no contest to) a crime involving fraud, dishonesty or moral turpitude or any felony.

Good Reason : is defined in each employment agreement as a termination by the executive in connection with or based upon (i) a material diminution in the executive s responsibilities, duties or authority, (ii) a material diminution in the executive s base compensation, (iii) assignment of the executive to a principal office located beyond a 50-mile radius of the executive s then current work place, or (iv) a material breach by us of any material provision of the employment agreement.

Each employment agreement also contains certain confidentiality covenants prohibiting each executive officer from, among other things, disclosing confidential information relating to our general partner or any of its affiliates, including us. The employment agreements also contain non-competition and non-solicitation restrictions, which apply during the term of the executive s employment with our general partner and continue for a period of 12 months following termination for any reason. If the executive s employment is terminated upon expiration of the initial or extended term of the agreement by either party upon 90 days written notice, the board of directors may, in its discretion, release the executive from being subject to the noncompetition covenant following termination of employment; however, in that case, the executive would not be entitled to receive any severance payment in connection with such termination.

Amended Phantom Unit Grant Agreements

Each of our named executive officers has received an award of phantom units under the LTIP. The terms of the phantom unit award agreements of our named executive officers provide that a termination due to death or disability results in full acceleration of vesting of any outstanding phantom units.

As discussed above, we do not expect to use DERs as an element of our compensation programs in the future and, on June 9, 2011, we amended each of the outstanding phantom unit grant agreements with our named executive officers to eliminate the DERs previously granted with our phantom units in exchange for a one-time aggregate payment of approximately $1.0 million. In addition to eliminating the DERs, the amendments also provided for acceleration of vesting of phantom units in certain cases in the event of a change of control. More specifically, all unvested phantom units held by a named executive officer will vest:

- on the closing date of a Change of Control transaction in which the surviving or acquiring entity does not assume and continue the unvested phantom units on the terms and conditions not less favorable than those provided under the LTIP and the award agreement immediately prior to such Change in Control;

- on the closing date of a Change of Control transaction in which the unitholders of the Partnership sell or exchange their interests in the Partnership for consideration comprised entirely of cash or a combination of cash and equity interests in the surviving or acquiring entity, but only with respect to the portion of the then-unvested phantom units equal to the percentage of all the consideration to such unitholders represented by cash;

- on the closing date of a Change of Control transaction in which the named executive officer is not offered or does not accept employment with the surviving or acquiring entity; or

- on the date of the named executive officer s termination of employment other than for Cause within one year after the closing date of a Change of Control transaction.

The following table shows the value of the severance benefits and other benefits for the named executive officers under the employment agreements and amended phantom unit grant agreements at December 31, 2011:

Name	Benefit Type	Death or Disability(a)	Termination Without Cause, or Upon Expiration(b)	Resignation for Good Reason	Certain Changes of Control (a)(c)
Brian F. Bierbach	Severance payment per employment agreement	None	$ 495,000	$ 495,000	None
	Accelerated vesting of phantom unit awards per award agreement	$ 682,302	None	None	$ 682,302
Sandra M. Flower	Severance payment per employment agreement	None	$ 257,000	$ 257,000	None
	Accelerated vesting of phantom unit awards per award agreement	$ 341,142	None	None	$ 341,142
Marty W. Patterson	Severance payment per employment agreement	None	$ 323,000	$ 323,000	None
	Accelerated vesting of phantom unit awards per award agreement	$ 341,142	None	None	$ 341,142
John J. Connor II	Severance payment per employment agreement	None	$ 323,000	$ 323,000	None
	Accelerated vesting of phantom unit awards per award agreement	$ 341,142	None	None	$ 341,142
William B. Mathews	Severance payment per employment agreement	None	$ 306,000	$ 306,000	None
	Accelerated vesting of phantom unit awards per award agreement	$ 170,562	None	None	$ 170,562

(a) The amounts shown in this column are calculated based on the fair market value of our common units which we have assumed for this purpose will be $18.17, multiplied by the number of split-adjusted phantom units that would vest.

(b) In connection with a termination of the executive s employment upon expiration of the initial or extended term of the agreement by either party pursuant to the terms of the employment agreement, the board of directors may, in its discretion, release the executive from being subject to the noncompetition covenant following termination of employment; however, in such case, the executive would not be entitled to receive the severance payment.

(c) Pursuant to the amended phantom unit award agreements, accelerated vesting of phantom units would only occur under certain types of change of control transactions, as described under Amended Phantom Unit Grant Agreements above.

Compensation of Directors

Each director who is not an officer or employee of our general partner receives compensation for attending meetings of the Board, as well as committee meetings, as follows:

a $50,000 annual cash retainer;

a $50,000 annual phantom unit grant; and

- where applicable, a committee chair retainer of $10,000 for each committee chaired.

In addition, each non-employee director will receive per meeting fees of:

- $1,000 for Board meetings attended in person;

- where applicable, $500 for Board committee meetings attended in person; and
- $500 for telephonic Board meetings and committee meetings greater than one hour in length.

We do not anticipate that Messrs. Moore or Page will participate in the annual phantom unit grant for the foreseeable future because each received a substantial phantom unit grant prior to our initial public offering. We expect Messrs. Moore and Page to receive the other elements of compensation outlined above.

Each non-employee director is also reimbursed for out-of-pocket expenses in connection with attending meetings of the Board or its committees. Each director will be fully indemnified by us for actions associated with being a director of our general partner to the extent permitted under Delaware law.

Each non-employee director listed in the table below has received grants of phantom units and accompanying DERs under our LTIP. In connection with eliminating the use of DERs as an element of our compensation programs in the future, we have amended the outstanding phantom unit award agreements with Messrs. Moore and Page to eliminate the DERs previously granted with the phantom units in exchange for a one-time aggregate payment of approximately $0.3 million. In addition to eliminating the DERs, the amendments also provide for acceleration of vesting of phantom units in certain cases in the event of a change of control. More specifically, all unvested phantom units held by such directors will vest:

- on the closing date of a Change of Control transaction in which the surviving or acquiring entity does not assume and continue the unvested phantom units on the terms and conditions not less favorable than those provided under the LTIP and the award agreement immediately prior to such Change in Control;
- on the closing date of a Change of Control transaction in which the unitholders of the Partnership sell or exchange their interests in the Partnership for consideration comprised entirely of cash or a combination of cash and equity interests in the surviving or acquiring entity, but only with respect to the portion of the then-unvested phantom units equal to the percentage of all the consideration to such unitholders represented by cash; or
- on the date of the director s termination of employment, if any, other than for Cause within one year after the closing date of a Change of Control transaction.

Director Compensation Table for 2011 and 2010

The following table sets forth the compensation paid to our non-employee directors for the years ended December 31, 2011 and 2010, as described above. The compensation paid in 2011 and 2010 to Mr. Bierbach as an executive officer is set forth in the Summary Compensation Table above. Mr. Bierbach did not receive any additional compensation related to his service as a director.

	Year	Fees Earned or Paid in Cash	Unit Awards (a)	All Other Compensation (b)	Total Compensation
Eileen A. Aptman	2011	$ 27,500	$	$	$ 27,500
	2010				
L. Kent Moore	2011	41,500	(c)	158,927	200,427
	2010	25,000		60,760	85,760
David L. Page	2011	48,000		158,128	206,128
	2010		623,991(c)		623,991
Gerald A. Tywoniuk	2011	42,764			42,764
	2010				

(a) The amount reported in this column represents the aggregate grant date fair value of the phantom unit award granted to Mr. Page as computed in accordance with FASB ASC Topic 718, which factors in the value of the accompanying DERs. Assumptions used in the calculation of these amounts are included in Note 14 to our audited consolidated financial statements included in this Form 10-K.

(b) The amount reported in this column represents the dollar value of distributions paid in 2011 and 2010 pursuant to DERs granted in connection with outstanding phantom unit awards including a one-time payment on June 9, 2011 in consideration for the elimination of the DER s previously granted. No such amounts are reported with respect to Mr. Page for 2010 due to the fact that the aggregate grant date fair value of his unit award reported in the above table factors in the value of the accompanying DERs.

(c) On March 2, 2010, Mr. Page received a split-adjusted grant of 24,267 phantom units, with 25% of such units vesting on each of the first through fourth anniversaries of the grant date. As of December 31, 2011, Mr. Page held an aggregate of 18,201 unvested phantom units.

On November 2, 2009, Mr. Moore received a split adjusted grant of 25,034 phantom units, with 25% of such units vesting on each of the first through fourth anniversaries of the grant date. As of December 31, 2011, Mr. Moore held an aggregate of 12,517 unvested phantom units.

Compensation Practices as They Relate to Risk Management

We do not believe that our compensation policies and practices create risks that are reasonably likely to have a material adverse effect on the partnership. We believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees). Short-term annual incentives are generally paid pursuant to discretionary bonuses enabling the Compensation Committee to assess the actual behavior of our employees as it relates to risk taking in awarding a bonus. Our use of equity based long-term compensation serves our compensation program s goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk taking.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth certain information regarding the beneficial ownership of units as of February 29, 2012 and the related transactions by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding;
- our general partner;
- each of the directors and named executive officers of our general partner; and
- all of the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be.

Our general partner is owned 100.0% by AIM Midstream Holdings. AIM holds an aggregate 84.4% indirect interest in AIM Midstream Holdings. Robert B. Hellman, Jr., Matthew P. Carbone and Edward O. Diffendal serve on the board of directors of our general partner and are principals of and have ownership interests in AIM. In addition, Brian F. Bierbach, the President and Chief Executive Officer of

our general partner and a member of the board of directors of our general partner, Marty W. Patterson, the Vice President of Commercial Affairs of our general partner, John J. Connor II, the Vice President of Operations of our general partner, Sandra M. Flower, the Vice President of Finance of our general partner, and William B. Mathews, the Secretary, General Counsel and Vice President of Legal Affairs of our general partner, have an aggregate 1.1% interest in AIM Midstream Holdings.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of December 31, 2011, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
AIM Universal Holdings, LLC (a)(b)	725,120	15.9%	4,526,066	100.0%	57.8%
AIM Midstream Holdings, LLC (b)	725,120	15.9%	4,526,066	100.0%	57.8%
The Northwest Mutual Life Insurance Company (d)	450,000	9.9%		0.0%	5.0%
Wellington Management Company, LLP (e)	393,300	8.6%		0.0%	8.6%
Fiduciary Asset Management Inc. (f)	371,650	8.1%		0.0%	4.1%
Robert B. Hellman, Jr. (b)		0.0%		0.0%	0.0%
Brian F. Bierbach (c)	*	*%		0.0%	*%
Sandra M. Flower (c)	*	*%		0.0%	*%
John J. Connor II (c)	*	*%		0.0%	*%
Marty W. Patterson (c)	*	*%		0.0%	*%
William B. Mathews (c)	*	*%		0.0%	*%
Eileen A. Aptman (c)		0.0%		0.0%	0.0%
Matthew P. Carbone (b)		0.0%		0.0%	0.0%
Edward O. Diffendal (b)		0.0%		0.0%	0.0%
David L. Page (c)	*	*%		0.0%	*%
L. Kent Moore (c)	*	*%		0.0%	*%
Gerald A. Tywoniuk (c)	*	*%		0.0%	*%
All directors and executive officers as a group (consisting of 12 persons)	84,774	1.9%		0.0%	0.9%

* An asterisk indicates that the person or entity owns less than one percent.

(a) AIM Universal Holdings, LLC, a Delaware limited liability company is the sole manager of AIM Midstream Holdings, LLC and may therefore be deemed to beneficially own the 725,120 common units and 4,526,066 subordinated units held by AIM Midstream Holdings. AIM Universal Holdings, LLC s members consist of Robert B. Hellman, Jr., and Matthew P. Carbone, both directors of our general partner.

(b) The address for this person or entity is 950 Tower Lane, Suite 800, Foster City, CA 94404

(c) The address for this person or entity is 1614 15th Street, Denver, CO 80202

(d) The address for this person or entity is 720 East Wisconsin Avenue, Milwaukee, WI 53202. This information is based solely on information included in the Schedule 13G/A filed by the beneficial owner on January 25, 2012.

(e) The address for this person or entity is 280 Congress Street, Boston, MA 02210. This information is based solely on information included in the Schedule 13G filed by the beneficial owner on February 14, 2012.

(f) The address for this person or entity is 8235 Forsyth Blvd, Suite 700, St. Louis, MO 63105. This information is based solely on information included in the Schedule 13G filed by the beneficial owner on February 14, 2012.

The percentage of units beneficially owned is based on a total of 9,087,102 common units and subordinated units outstanding at December 31, 2011.

Item 13. Certain Relationships and Related Transactions and Director Independence

At December 31, 2011, AIM Midstream Holdings owned 725,120 common units and 4,526,066 subordinated units, representing a combined 57.8% limited partner interest in us. In addition, AIM Midstream Holdings owns and controls our general partner, which owns a 2.0% general partner interest in us and all of our incentive distribution rights.

Distributions and Payments to our General Partner and its Affiliates

The following summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and any liquidation of American Midstream Partners, LP. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Distributions of available cash to our general partner and its affiliates:

We will initially make cash distributions 98.0% to our unitholders pro rata, including AIM Midstream Holdings, as the holder of an aggregate of 725,120 common units and 4,526,066 subordinated units, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% general partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the incentive distribution rights held by our general partner will entitle our general partner to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level.

Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $0.3 million on its 2.0% general partner interest and AIM Midstream Holdings would receive an annual distribution of approximately $8.7 million on its common units and subordinated units.

Payments to our general partner and its affiliates

Our general partner will not receive a management fee or other compensation for its management of us. However, we will reimburse our general partner and its affiliates for all expenses incurred on our behalf. Our partnership agreement provides that our general partner will determine the amount of these reimbursed expenses.

Withdrawal or removal of our general partner

If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Ownership Interests of Certain Executive Officers and Directors of Our General Partner

AIM Midstream Holdings owns 100.0% of our general partner. AIM, Eagle River Ventures, LLC, Stockwell Fund II, L.P. and certain of our executive officers own all of the equity interests in AIM Midstream Holdings. In addition, Robert B. Hellman, Jr., Matthew P. Carbone and Edward O. Diffendal serve on the board of directors of our general partner and are principals of AIM.

In addition to the 2.0% general partner interest in us, our general partner owns the incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 48.0%, of the cash we distribute in excess of $0.47438 per unit per quarter.

Agreements with Affiliates

We and other parties have or will enter into the various documents and agreements with certain of our affiliates, as described in more detail below. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm s-length negotiations.

Advisory Services Agreement

In October 2009, our subsidiary, American Midstream, LLC 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. Under this agreement, the advisors performed certain financial and advisory services for American Midstream, LLC. No fees or reimbursements were paid to the advisors during 2009 in respect of this agreement. During the year ended December 31, 2011 and 2010, American Midstream, LLC paid the advisors $0.1 million and $0.3 million, respectively, for such services and reimbursed the advisors $0.1 million and $0.2 million, respectively, for the advisors actual and direct out-of-pocket expenses incurred in the performance of their services. In connection with the closing of our initial public offering, the advisory services agreement was terminated in exchange for an aggregate payment of $2.5 million from us to the advisors.

Contribution Agreements

In October 2009, a contribution and sale agreement was entered into by AIM Midstream Holdings and AIM Midstream, LLC, American Infrastructure MLP Fund, L.P., American Infrastructure MLP Private Equity Fund, L.P., American Infrastructure MLP Associates Fund, L.P., Brian F. Bierbach, Marty W. Patterson, John J. Connor II, Eagle River Ventures, LLC, and Stockwell Fund II, L.P., as investors, and AIM Universal Holdings, LLC. Pursuant to this agreement, the investors contributed an aggregate of $100 million to AIM Midstream Holdings in exchange for membership interests in AIM Midstream Holdings.

In November 2009, we entered into a contribution, conveyance and assumption agreement with AIM Midstream Holdings, American Midstream GP, American Midstream, LLC, and American Midstream Marketing, LLC. Pursuant to this Agreement, AIM Midstream Holdings contributed $2 million to American Midstream GP in exchange for all of the outstanding membership interests in American Midstream GP. American Midstream GP, in turn, contributed such $2 million to us in exchange for 97,070 split adjusted general partner units representing a 2% general partner interest in us, and all of our incentive distribution rights. AIM Midstream Holdings also contributed $98 million to us in exchange for 4,756,433 split-adjusted common units representing a 98% limited partner interest in us. We then contributed the $100 million that we received from American Midstream GP and AIM Midstream Holdings to American Midstream, LLC in exchange for the continuation of our 100% member interest in American Midstream, LLC.

In September 2010, a contribution and sale agreement was entered into by AIM Midstream Holdings and AIM Midstream, LLC, American Infrastructure MLP Fund, L.P., American Midstream MLP Associates Fund, L.P., American Infrastructure MLP Private Equity Fund, L.P., Eagle River Ventures, LLC, Stockwell Fund II, L.P., John J. Connor II, William B. Mathews, and Sandra M. Flower, as investors. Pursuant to this agreement, the investors contributed an aggregate of $12 million to AIM Midstream Holdings in exchange for membership interests in AIM Midstream Holdings.

In September 2010, we entered into a contribution agreement with AIM Midstream Holdings, our general partner, and American Midstream, LLC. Pursuant to this Agreement, AIM Midstream Holdings contributed $240,000, or 2% of the $12 million contributed by the investors to AIM Midstream Holdings pursuant to the contribution and sale agreement described in the preceding paragraph, to our general partner. Our general partner, in turn, contributed such $240,000 to us in exchange for 11,648 split-adjusted general partner units. AIM Midstream Holdings also contributed $11,760,000, or 98% of the $12 million contributed by the investors to AIM Midstream Holdings pursuant to the contribution and sale agreement described in the preceding paragraph, to us in exchange for 570,772 split-adjusted common units. We then contributed the $12 million that we received from American Midstream GP and AIM Midstream Holdings to American Midstream, LLC in furtherance of our existing limited liability company interest American Midstream, LLC.

Procedures for Review, Approval and Ratification of Related-Person Transactions

The board of directors of our general partner has adopted a code of business conduct and ethics provides that the board of directors of our general partner or its authorized committee will periodically review all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related-person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics provides that, in determining whether to recommend the initial approval or ratification of a related-person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions; (iv) the impact of the transaction on director independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The code of business conduct and ethics described above was adopted in connection with the closing of our initial public offering, and as a result the transactions described above were not reviewed under such policy.

Item 14. Principal Accountant Fees and Services

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP for tax, independent auditing and related services for each of the last two years:

	Year Ended December 31,	
	2011	**2010**
	(in thousands)	
Audit fees (1)	$ 1,432	$ 316
Audit related fees (2)	73	
Tax fees (3)	94	48
All other fees (4)		
	$ 1,599	$ 364

(1) Audit fees primarily present professional services rendered in connection with our IPO, the audits of our annual financial statements for the fiscal years 2011 and 2010, (ii) quarterly reviews of our financial statements included in Forms 10-Q, (iii) the audits of our FERC regulated assets for the fiscal years 2011 and 2010, and (iv) and those services normally provided in connection with the issuance of consents and other services related to SEC matters

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not under audit fees. For the year ended December 31, 2011, the amounts reported represent carve-out audit fees associated with the acquisition of the 50% undivided interest in the Burns Point Plant. No such services were rendered by PricewaterhouseCoopers LLP during 2010.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder K-1 statements as well as partnership tax compliance and tax planning.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the categories listed in the table above. No such services were rendered by PricewaterhouseCoopers LLP during the last two years.

Our Audit Committee approved the use of PricewaterhouseCoopers LLP as our independent registered public accounting firm to conduct the audit of our consolidated financial statements for the year ended December 31, 2011. All services provided by our independent auditor are subject to pre-approval by the Audit Committee. The Audit Committee is informed of each engagement of the independent auditor to provide services to us.

PART III

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of the Annual Report. For a listing of these items and accompanying footnotes, see Index to Financial Statements: Page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All other schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto or will be filed within the required timeframe.

(a)(3) Exhibits

1.1	Underwriting Agreement between American Midstream Partners, LP and Citigroup Global Markets Inc. and Merrill Lynch, Pierce, Fenner and Smith as representatives of several underwriters (incorporated by reference to Exhibit 1.1 to American Midstream Partners, LP Form S-1/A filed June 30, 2011 (File No. 333-173191))
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP Form S-1 filed March 31, 2011 (File No. 333-173191))
3.1	Second Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP Form 8-K filed August 4, 2011 (File No 001-35257))
3.2	First Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to American Midstream Partners, LP Form S-1 filed March 31, 2011 (File No. 333-173191))
3.4	Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to American Midstream Partners, LP Form S-1 filed March 31, 2011 (File No. 333-173191))
3.5	Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC A Delaware Limited Liability Company Dated as of November 4, 2009 (incorporated by reference to Exhibit 3.5 to American Midstream Partners, LP Form S-1 filed March 31, 2011 (File No. 333-173191))
3.6	First Amendment to Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.6 to American Midstream Partners, LP Form S-1/A filed July 1, 2011 (File No. 333-173191))
5.1	Legal Consent (incorporated by reference to Exhibit 5.1 to American Midstream Partners, LP Form S-1 filed June 9, 2011 (File No. 333-173191))
8.1	Legal Opinion Letter (incorporated by reference to Exhibit 8.1 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.1	Revolving and Term Loan Credit Agreement Dated as of October 5, 2009 between American Midstream, LLC, Comerica Bank, BBVA Compass Bank (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.2	First Amendment to Revolving and Term Loan Credit Agreement (incorporated by reference to Exhibit 10.2 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.3	Second Amendment and Waiver to Revolving and Term Loan Credit Agreement (incorporated by reference to Exhibit 10.3 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.4+	Employment Agreement between Brian F. Bierbach and American Midstream GP, LLC (incorporated by reference to Exhibit 10.4 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.5+	Employment Agreement between Marty W. Patterson and American Midstream GP, LLC (incorporated by reference to Exhibit 10.5 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))

10.6+	Employment Agreement between John J. Connor II and American Midstream GP, LLC (incorporated by reference to Exhibit 10.6 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.7+	Amended and Restated American Midstream GP, LLC Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.8+	Form of American Midstream Partners, LP Long Term Incentive Plan Grant of Phantom Units (incorporated by reference to Exhibit 10.8 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.9	Gas Processing Agreement between American Midstream (Louisiana Intrastate), LLC and Enterprise Gas Processing, LLC dated June 1. 2011 (incorporated by reference to Exhibit 10.9 to American Midstream Partners, LP Form S-1/A filed July 13, 2011 (File No. 333-173191))
10.10	Firm Gas Gathering Agreement Between American Midstream (Seacrest) LP and Contango Resources Company (incorporated by reference to Exhibit 10.10 to American Midstream Partners, LP Form S-1/A filed June 2, 2011 (File No. 333-173191))

10.11	Amendment to Firm Gas Gathering Agreement between American Midstream Offshore (Seacrest) LP (formerly Enbridge Offshore Pipelines (Seacrest) L.P.) and Contango Operators, Inc. (formerly Contango Resources Company) dated as of August 1, 2008 (incorporated by reference to Exhibit 10.11 to American Midstream Partners, LP Form S-1/A filed June 2, 2011 (File No. 333-173191))
10.12	Base Contract for Sale and Purchase of Natural Gas Between Exxon Gas & Power Marketing Company and Mid Louisiana Gas Transmission, LLC (incorporated by reference to Exhibit 10.12 to American Midstream Partners, LP Form S-1/A filed June 2, 2011 (File No. 333-173191))
10.13	Gas Processing Agreement Between American Midstream (Mississippi) LLC and Venture Oil and Gas, Inc. (incorporated by reference to Exhibit 10.13 to American Midstream Partners, LP Form S-1/A filed June 2, 2011 (File No. 333-173191))
10.14	Gas Transport Contract between Midcoast Interstate Transmission, Inc. and City of Decatur Utilities (incorporated by reference to Exhibit 10.14 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.15	Amendment No. 1 to Gas Transportation Contract between Enbridge Pipelines (AlaTenn) Inc. and the City of Decatur (incorporated by reference to Exhibit 10.15 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.16	Natural Gas Pipeline Construction and Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.16 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.17	First Amendment to Natural Gas Pipeline Construction and Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.17 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.18	Natural Gas Pipeline Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.18 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.19	First Amendment to Natural Gas Pipeline Construction and Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.19 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.20	Gas Transport Contract between Enbridge Pipelines (AlaTenn), L.L.C. and the City of Huntsville (incorporated by reference to Exhibit 10.20 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.21	Service Agreement between Enbridge Pipelines (Midla), L.L.C. and Enbridge Marketing, LP dated September 1, 2008 (incorporated by reference to Exhibit 10.21 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.22	Service Agreement between Enbridge Pipelines (Midla), L.L.C. and Enbridge Marketing, LP dated September 1, 2008 (incorporated by reference to Exhibit 10.22 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.23	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC and Enterprise Gas Processing dated July 1, 2010 (incorporated by reference to Exhibit 10.23 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.24	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC and Enterprise Gas Processing dated November 1, 2010 (incorporated by reference to Exhibit 10.24 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.25	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC and Enterprise Gas Processing dated April 1, 2011 (incorporated by reference to Exhibit 10.25 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.26+	Employment Agreement between Sandra M. Flower and American Midstream GP, LLC (incorporated by reference to Exhibit 10.26 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.27+	Employment Agreement between William B. Mathews and American Midstream GP, LLC (incorporated by reference to Exhibit 10.27 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.28+	Form of Amendment of Grant of Phantom Units Under the American Midstream Partners, LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))

10.29	Credit Agreement among American Midstream, LLC, American Midstream, LP, Bank of America, N.A., Comerica Bank, Citicorp North America, BBVA Compass and Merrill Lynch, Pierce, Fenner& Smith (incorporated by reference to Exhibit 10.29 to American Midstream Partners, LP Form S-1/A filed June 30, 2011 (File No. 333-173191))
10.30*	Burns Point Plant Interest Purchase and Sale Agreement, dated November 15, 2011 between Marathon Oil Company and American Midstream Partners, LLC
10.31*	Amendment to the Burns Point Plant Interest Purchase and Sale Agreement dated December 1, 2011 between Marathon Oil Company and American Midstream Partners, LLC
21.1	American Midstream Partners, LP List of Subsidiaries (incorporated by reference to Exhibit 21.1 to American Midstream Partners, LP Form S-1 filed March 31, 2011 (File No. 333-173191))
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of Independent Registered Public Accounting Firm
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

31.2*	Certification of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted 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 Taonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

\+ Management contract or compensatory plan arrangement

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

American Midstream Partners, LP
(Registrant)

By: /s/ Sandra M. Flower

Sandra M. Flower
Vice President of Finance
(Principal Financial Officer)

Date: March 19, 2012

Pursuant to the requirements of the Securities Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 19th, 2012.

Signatures	**Title (Position with American Midstream Partners, LP)**
/s/ Brian F. Bierbach Brian F. Bierbach	Director, President and Chief Executive Officer (Principal Executive Officer)
/s/ Sandra M. Flower Sandra M. Flower	Vice President of Finance (Principal Financial and Accounting Officer)
/s/ Robert B. Hellman, Jr. Robert B. Hellman, Jr.	Chairman of the Board
/s/ Eileen A. Aptman Eileen A. Aptman	Director
/s/ Matthew P. Carbone Matthew P. Carbone	Director
/s/ Edward O. Diffendal Edward O. Diffendal	Director
/s/ L. Kent Moore L. Kent Moore	Director
/s/ David L. Page David L. Page	Director
/s/ Gerald A. Tywoniuk Gerald A. Tywoniuk	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

AMERICAN MIDSTREAM PARTNERS, LP AUDITED CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner of

American Midstream Partners, LP

We have audited the accompanying consolidated balance sheets of American Midstream Partners, LP and its subsidiaries as of December 31, 2011 and 2010 and the related consolidated statements of operations, of changes in partners   capital and of cash flows for the years ended December 31, 2011 and 2010 and the period from August 20, 2009 (inception date) to December 31, 2009. These financial statements are the responsibility of the Partnership   s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Midstream Partners, LP and its subsidiaries at December 31, 2011 and 2010 and the results of their operations and their cash flows for the years ended December 31, 2011 and 2010 and the period from August 20, 2009 (inception date) to December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado

March 19, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner of

American Midstream Partners, LP

We have audited the accompanying combined statement of operations of American Midstream Partners Predecessor (the Predecessor), and the related combined statements of group equity and of cash flows for the ten-month period ended October 31, 2009. These financial statements are the responsibility of American Midstream Partners, LP. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the results of operations of American Midstream Predecessor and their cash flows for the ten-month period ended October 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 17 to the financial statements, the financial results contain significant transactions with related parties.

/s/ PricewaterhouseCoopers, LLP

Houston, Texas

March 30, 2011

American Midstream Partners, LP and Subsidiaries

Consolidated Balance Sheets

(In thousands except unit amounts)

	December 31, 2011	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 871	$ 63
Accounts receivable	1,218	656
Unbilled revenue	19,745	22,194
Risk management assets	456	
Other current assets	3,323	1,523
Total current assets	25,613	24,436
Property, plant and equipment, net	170,231	146,808
Other assets, net	3,707	1,985
Total assets	$ 199,551	$ 173,229
Liabilities and Partners Capital		
Current liabilities		
Accounts payable	$ 837	$ 980
Accrued gas purchases	14,715	18,706
Current portion of long-term debt		6,000
Other loans		615
Risk management liabilities	635	
Accrued expenses and other current liabilities	7,086	2,676
Total current liabilities	23,273	28,977
Other liabilities	8,612	8,078
Long-term debt	66,270	50,370
Total liabilities	98,155	87,425
Commitments and contingencies (see Note 16)		
Partners capital		
General partner interest (0.2 and 0.1 million units issued and outstanding as of December 31, 2011 and 2010, respectively)	1,091	2,124
Limited partner interest (9.1 and 5.4 million units issued and outstanding as of December 31, 2011 and 2010, respectively)	99,890	83,624
Accumulated other comprehensive income	415	56
Total partners capital	101,396	85,804
Total liabilities and partners capital	$ 199,551	$ 173,229

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

American Midstream Partners, LP and Subsidiaries

Consolidated Statements of Operations

(In thousands, except per unit amounts)

	For the Year Ended December 31, 2011	For the Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
Revenue	$ 248,282	$ 212,248	$ 32,833	$ 143,132
Realized gain (loss) on early termination of commodity derivatives	(2,998)			
Unrealized gain (loss) on commodity derivatives	(541)	(308)		
Total revenue	244,743	211,940	32,833	143,132
Operating expenses:				
Purchases of natural gas, NGLs and condensate	202,403	173,821	26,593	113,227
Direct operating expenses	12,856	12,187	1,594	10,331
Selling, general and administrative expenses	10,794	7,120	1,196	8,553
Advisory services agreement termination fee (See Note 17)	2,500			
Transaction expenses (See Note 2)	282	303	6,404	
Equity compensation expense (See Note 14)	3,357	1,734	150	
Depreciation and accretion expense	20,705	20,013	2,978	12,630
Total operating expenses	252,897	215,178	38,915	144,741
Gain (loss) on acquisition of assets	565			
Gain (loss) on sale of assets, net	399			
Operating income (loss)	(7,190)	(3,238)	(6,082)	(1,609)
Other income (expenses):				
Interest expense	(4,508)	(5,406)	(910)	(3,728)
Net income (loss)	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
General partner s interest in net income (loss)	(233)	(173)	(140)	
Limited partners interest in net income (loss)	$ (11,465)	$ (8,471)	$ (6,852)	
Limited partners net income (loss) per unit (See Note 19)	$ (1.64)	$ (1.66)	$ (3.13)	
Weighted average number of units used in computation of limited partners net income (loss) per unit	6,997	5,099	2,187	

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

American Midstream Partners, LP and Subsidiaries

Consolidated Statements of Changes in Partners Capital

(In thousands)

	Limited Partner Common Units	Limited Partner Subordinated Units	Group Equity	Limited Partner Interest	General Partner Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
Predecessor:								
Balance at December 31, 2008			$ 151,799					$ 151,799
Net income (loss)			(5,337)					(5,337)
Contributions by parent			111,103					111,103
Distributions to parent			(25,772)					(25,772)
Other comprehensive loss			(201)					(201)
Balance at October 31, 2009			$ 231,592	$		$	$	$ 231,592
Successor:								
Balances at August 20, 2009 (Inception date)				$		$	$	$
Net income (loss)				(6,852)		(140)		(6,992)
Unitholder contributions	4,756			98,000	97	2,000		100,000
Unitholder distributions								
Unit based compensation						150		150
Adjustments to other post retirement plan assets and liabilities							46	46
Balances at December 31, 2009	4,756			91,148	97	2,010	46	93,204
Net income (loss)				(8,471)		(173)		(8,644)
Unitholder contributions	571			11,760	12	240		12,000
Unitholder distributions				(11,545)		(234)		(11,779)
LTIP vesting	44			903		(903)		
Tax netting repurchase	(8)			(171)				(171)
Unit based compensation						1,184		1,184
Adjustments to other post retirement plan assets and liabilities							10	10
Balances at December 31, 2010	5,363			83,624	109	2,124	56	85,804
Net income (loss)				(11,465)		(233)		(11,698)
Recapitalization	(4,602)	4,526			76			
Issuance of common units to public, net of offering costs	3,750			69,085				69,085
Unitholder distributions				(42,682)		(864)		(43,546)
LTIP vesting	62			1,286		(1,286)		
Tax netting repurchase	(12)			(215)				(215)
Unit based compensation				257		1,350		1,607
Adjustments to other post retirement plan assets and liabilities							359	359
Balances at December 31, 2011	4,561	4,526	$	$ 99,890	185	$ 1,091	$ 415	$ 101,396

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

American Midstream Partners, LP and Subsidiaries

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
Cash flows from operating activities				
Net income (loss)	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
Adjustments to reconcile net income (loss) to net cash provided (used) in from operating activities:				
Depreciation and accretion expense	20,705	20,013	2,978	12,630
Amortization of deferred financing costs	1,262	807	118	
Mark-to-market on derivatives	849	385	5	
Unit based compensation	1,607	1,185	150	
OPEB plan net periodic (benefit) cost	(82)			
(Gain) loss on acquisition of assets	(565)			
(Gain) loss on sale of assets	(399)			
Changes in operating assets and liabilities:				
Accounts receivable	(562)	791	(1,447)	1,163
Unbilled revenue	2,449	(3,865)	(18,329)	(387)
Due from affiliates				(13,144)
Notes receivable from affiliates				26,872
Risk management assets	(670)	(308)	(82)	
Other current assets	(1,800)		(1,523)	646
Other assets, net	(54)	(104)	(199)	(320)
Accounts payable	(218)	(954)	1,934	1,242
Accrued gas purchases	(3,991)	3,825	14,881	(8,113)
Accrued expenses and other current liabilities	4,410	268	1,997	(922)
Other liabilities	(811)	392	(22)	259
Net cash provided (used) in operating activities	10,432	13,791	(6,531)	14,589
Cash flows from investing activities				
Acquisition of operating assets from Enbridge Midcoast Energy, LP			(150,818)	
Acquisition of 50% interest in Burns Point Gas Plant from Marathon Oil Company	(35,500)			
Additions to property, plant and equipment	(6,369)	(10,268)	(1,158)	(853)
Proceeds from disposals of property, plant and equipment	125			
Net cash provided (used) in investing activities	(41,744)	(10,268)	(151,976)	(853)
Cash flows from financing activities				
Unit holder distributions	(43,546)	(11,779)		
Contributions from parent				111,103
Proceeds upon issuance of common units to public, net of offering costs	69,085			
Unit holder contributions		12,000	100,000	
LTIP tax netting unit repurchase	(215)			
Distributions to parent				(25,772)
Payments on other loan	(615)	(1,000)	(89)	
Borrowings on other loan		800	903	

Repayments of notes to affiliates				(39,339)
Deferred debt issuance costs	(2,489)		(2,158)	
Borrowings on long-term debt	130,570	26,500	63,000	
Payments on long-term debt	(120,670)	(31,130)	(2,000)	(60,000)
Net cash provided (used) in financing activities	32,120	(4,609)	159,656	(14,008)
Net increase (decrease) in cash and cash equivalents	808	(1,086)	1,149	(272)
Cash and cash equivalents				
Beginning of period	63	1,149		421
End of period	$ 871	$ 63	$ 1,149	$ 149
Supplemental cash flow information				
Interest payments	$ 3,349	$ 4,523	$ 337	132
Supplemental non-cash information				
Accrual of property, plant and equipment	$ 75	$	$	$
Accrual of asset retirement obligation	$ 872	$ 6,058	$	$

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

American Midstream Partners LP and Subsidiaries

Notes to 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.

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

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

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

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

Basis of Presentation

We have prepared the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP). The accompanying consolidated financial statements include accounts of American Midstream Partners, LP and its controlled subsidiaries. All significant inter-company accounts and transactions have been eliminated in the preparation of the accompanying consolidated financial statements.

Since we acquired our assets from Enbridge Midcoast Energy, L.P. effective November 1, 2009, the financial and operational data for 2009 is bifurcated between the period that American Midstream Partners Predecessor (our Predecessor) owned those assets and the period from our acquisition through the end of the year. Moreover, there is some overlap between these two periods resulting from the fact that we were formed on August 20, 2009, which was prior to the acquisition on November 1, 2009. As a result, the 2009 period that our Predecessor owned and operated the assets is the ten months ended October 31, 2009, while the successor 2009 period begins with our inception on August 20, 2009 and ends on December 31, 2009. Between the date of inception and the date of acquisition of the assets discussed in Note 2 on November 1, 2009, no operating activity occurred in the partnership.

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

Consolidation Policy

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

Use of Estimates

When preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Accounting for Regulated Operations

Certain of our natural gas pipelines are subject to regulations by the FERC. The FERC exercises statutory authority over matters such as construction, transportation rates we charge and our underlying accounting practices and ratemaking agreements with customers. Accordingly, we record costs that are allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a non-regulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would be recorded under GAAP for our regulated entities. As of December 31, 2011 and 2010, we had no such material regulatory assets or liabilities.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

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 year ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, respectively, we recognized the following revenues by category:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	(in thousands)			
Revenue				
Transportation - firm	$ 10,504	$ 10,610	$ 2,274	$ 10,616
Transportation - interruptible	3,583	3,313	444	1,662
Sales of natural gas, NGLs and condensate	233,319	197,706	30,078	129,673
Other	1,184	619	37	1,181
Realized gain (loss) on early termination of commodity derivatives	(2,998)			
Realized loss on expiration of commodity put contract	(308)			
Unrealized gain (loss) on commodity derivatives	(541)	(308)		
Total revenue	$ 244,743	$ 211,940	$ 32,833	$ 143,132

Fee-based

Under these arrangements, we generally are paid a fixed cash fee for gathering and transporting natural gas. Fee-based revenues, which are included in sales of natural gas, NGLs and condensate above, are recorded when services have been provided, and collectability of the revenue is reasonably assured.

Percent-of-proceeds, or POP

Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas and NGLs at market prices. Where we provide processing services at the processing plants that we own, or obtain processing service for our own account under our own elective processing arrangements we typically retain and sell a percentage of the residue natural gas and resulting NGLs. We recognize percent-of-proceeds contract revenue, which is included in sales of natural gas, NGLs and condensate above, when the natural gas, NGLs or condensate is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured.

Fixed-margin

Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. We recognize revenue from fixed-margin contracts, which is included in sales of natural gas, NGLs and condensate, above, when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred and collectability of the revenue is reasonably assured.

Firm transportation

Our obligation to provide firm transportation service means that we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a variable use charge with respect to quantities actually transported by us. Firm transportation revenue is recorded when products are delivered, services have been provided and collectability of the revenue is reasonably assured.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

Interruptible transportation

Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent we have available capacity. For this service the shipper pays no reservation charge but pays a variable use charge for quantities actually shipped. Interruptible transportation revenue is recorded when products are delivered, services have been provided and collectability of revenue is reasonably assured.

Interest in the Burns Point Plant

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

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less at the date of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. For each of the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, the Partnership recorded no allowances for losses on accounts receivable.

Inventory

Inventory includes NGL product inventory. The Partnership records all product inventories at the lower of cost or market (LCM), which is determined on a weighted average basis and included within other current assets on the consolidated balance sheets.

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a natural gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in-kind through future receipt or delivery of natural gas. Natural gas imbalances are recorded as gas imbalances and classified within other current assets or other current liabilities on our consolidated balance sheets based on the market value.

Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives of which have been extended; and (3) all land, regardless of cost. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

We record property, plant, and equipment at its original cost, which we depreciate on a straight-line basis over its estimated useful life. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We record depreciation using the group method of depreciation, which is commonly used by pipelines, utilities and similar assets.

The Partnership calculated the fair value of assets acquired from Enbridge Pipelines, LP in November 2009 and the assets acquired from Marathon Oil Company in December 2011 with the assistance of an independent third party valuation firm. These valuations were performed primarily using a discounted cash flow model that included certain market assumptions related to future throughput discount rates. We created the projections and reviewed the calculations, assumptions and valuation methodology used to determine the fair value of the assets acquired. We determined the final fair values to assign to the assets and liabilities in determining the purchase price allocation and had sole responsibility for those items in the financial statements.

Impairment of long Lived Assets

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our business, the market, and business environment to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income. No impairment losses were recognized during the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

We assess our long lived assets for impairment using authoritative guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value. Fair values, for the purposes of the impairment test, are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:

- A significant decrease in the market price of a long-lived asset or group;
- A significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;
- A significant adverse change in legal factors or in the business climate could affect the value of long-lived asset or asset group, including an adverse action or assessment by a regulator which would exclude allowable costs from the rate-making process;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of the long-lived asset or asset group;
- A current-period operating cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long lived asset or asset group; and
- A current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

Income Taxes

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws by the State of Texas that apply to entities organized as partnerships and is included in selling, general and administrative expenses in the consolidated statements of operations. The Texas margin tax is computed on our modified gross margin and was not significant for each of the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009.

Net income for financial statement purposes may differ significantly for taxable income allocable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirement under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner s tax attributes in us is not available.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur from the remediation of existing environmental contamination caused by past operations that do not benefit future period by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulation taking into consideration the likely effects of inflation and other factors. These amounts also take into account our prior experience in remediating contaminated sites, other companies clean-up experience and date released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount or if no amount in more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our offshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement of estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management s experience, or the asset s estimated economic life. The useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exist to reasonably estimate potential settlement dates and methods.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

Asset Retirement Obligations (AROs)

AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset s acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. We depreciate the capitalized ARO using the straight-line method over the period during which the related long-lived asset is expected to provide benefits. After the initial period of ARO recognition, we revise the ARO to reflect the passage of time or revisions to the amount of estimated cash flows or their timing.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt, commodity prices and fractionation margins (the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). In an effort to manage the risks to unitholders, we use a variety of derivative financial instruments including swaps, put options and interest rate caps to create offsetting positions to specific commodity or interest rate exposures. In accordance with the authoritative accounting guidance, we record all derivative financial instruments in our consolidated balance sheets at fair market value. We record the fair market value of our derivative financial instruments in the consolidated balance sheet as current and long-term assets or liabilities on a net basis by counterparty. We record changes in the fair value of our derivative financial instruments in our consolidated statements of operations as follows:

Commodity-based derivatives:	Total revenue
Corporate interest rate derivatives:	Interest expense

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the board of directors of our general partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction, and we do not use derivative financial instruments for speculative purposes.

The price assumptions we use to value our derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from over-the-counter, or OTC, market makers to find executable bids and offers. The valuations also reflect the potential impact of conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Our earnings are affected by use of mark-to-market method of accounting as required under GAAP for derivative financial instruments. The use of mark-to-market accounting for derivative financial instruments can cause noncash earnings volatility resulting from changes in the underlying indices, primarily commodity prices.

Comprehensive Income (loss)

The Partnership s other comprehensive income (loss) is comprised of changes in the net pension asset or liability associated with the OPEB plan (Note 15). Comprehensive income (loss) for the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009 is as follows:

	Period from August 20, 2009 (Inception Date)	Predecessor Ten Months

	Year Ended December 31, 2011	2010	to December 31, 2009	ended October 31, 2009
	(in thousands)			
Net income (loss)	$ (11,698)	$ (8,644)	$ (6,992)	$ (5,337)
Unrealized gains (losses) on post retirement benefit plan assets and liabilities	359	10	46	(201)
Compreshensive income (loss)	$ (11,339)	$ (8,634)	$ (6,946)	$ (5,538)

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

Unit-Based Employee Compensation

We award unit-based compensation to management, non-management employees and directors in the form of phantom units, which are deemed to be equity awards. Compensation expense on phantom units is measured by the fair value of the award at the date of grant as determined by management. Compensation expense is recognized in equity compensation expense over the requisite service period of each award. See Note 14.

Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of our derivative instruments and disclosures associated with our outstanding indebtedness. We define fair value as an exit price representing the expected amount we would receive when selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

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

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

Level 1 We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other ant quoted prices in active markets for the identical instrument, as a Level 2. Assets and liabilities that we value using either models or other valuation methodologies are derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include debt and derivative instruments for which we do not have sufficient corroborating market evidence support classifying the asset or liability as Level 2. Additionally, Level 3 valuations may utilize modeled pricing inputs to derive forward valuations, which may include some or all of the following inputs: nonbinding broker quotes, time value, volatility, correlation and extrapolation methods.

We utilize a mid-market pricing convention, or the market approach , for valuation for assigning fair value to our derivative assets and liabilities. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt. Gains or losses on debt repurchase and debt extinguishment include any associated unamortized debt issue costs.

Limited Partners Net Income (Loss) Per Unit

We compute limited partners net income (loss) per unit by dividing our limited partners interest in net income (loss) by the weighted average number of units outstanding during the period. The overall computation, presentation and disclosure of our limited partners net income (loss) per unit are made in accordance with the FASB Accounting Standards Codification (ASC) Topic 260 Earnings per Share .

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

Recent Accounting Pronouncements

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

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

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

2. Acquisitions

Burns Point Plant Interest

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

The Plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The Plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. The Partnership s Quivira system currently supplies approximately 85% of the inlet volume to the Plant. The residue gas is transported, via pipeline to Gulf South and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC (Promix), an Enterprise operated fractionator. The current capacity of the plant is 165 MMcf/d. The acquisition complemented our existing assets given the location of the Plant in comparison to the Quivira system and is included in our gathering and processing segment.

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

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

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

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

	(in thousands)
Consideration paid to seller	
Cash consideration	$ 35,500
Recognized amounts of identifiable assets acquired and liabilities assumed	
Property, plant and equipment	$ 36,065
Liabilities assumed	
Total identifiable net assets	36,065
Bargain purchase (gain)	(565)
	$ 35,500

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

Fair value of the assets calculated under the market participant approach was in excess of cash consideration paid resulting in a $0.6 million bargain purchase gain.

Pro forma consolidated information

The following unaudited pro forma consolidated information sets forth our unaudited historical and pro forma consolidated statements of operations for the years ended December 31, 2011 and 2010.

The unaudited pro forma consolidated statements of operations for the years ended December 31, 2011 and 2010, give effect to the acquisition by us of the Interest as if it had occurred on January 1, 2010.

The unaudited pro forma adjustments are based on available information and certain assumptions we believe are reasonable.

The unaudited pro forma consolidated financial information is for informational purposes only and is not intended to represent or be indicative of the consolidated results of operations or financial position that we would have reported had this acquisition been completed on the date indicated and should not be taken as representative of its future consolidated results of operations or financial position. Further, the unaudited pro forma consolidated statement of operations is not indicative of the operations going forward because it necessarily excludes various operating expenses.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

	Year Ended December 31, 2011			Year Ended December 31, 2010		
	American Midstream Partners, LP as previously reported	**Pro forma adjustments**	**American Midstream Partners, LP pro forma**	**American Midstream Partners, LP as previously reported**	**Pro forma adjustments**	**American Midstream Partners, LP pro forma**
			(unaudited in thousands, except per unit amounts)			
Revenue	$ 248,282	$ 5,165(a)	$ 253,447	$ 212,248	$ 4,645(a)	$ 216,893
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)			
Unrealized gain (loss) on commodity derivatives	(541)		(541)	(308)		(308)
Total revenue	244,743	5,165	249,908	211,940	4,645	216,585
Operating expenses:						
Purchases of natural gas, NGLs and condensate	202,403		202,403	173,821		173,821
Direct operating expenses	12,856	1,290(b)	14,146	12,187	1,805(b)	13,992
Selling, general and administrative expenses	10,794		10,794	7,120		7,120
Advisory services agreement termination fee	2,500		2,500			
Transaction expenses	282		282	303		303
Equity compensation expense	3,357		3,357	1,734		1,734
Depreciation expense	20,705	751(c)	21,456	20,013	902(c)	20,915
Total operating expenses	252,897	2,041	254,938	215,178	2,707	217,885
Gain on purchase of assets	565	(565)(g)			565(e)	565
Gain (loss) on sale of assets, net	399		399			
Operating income (loss)	(7,190)	2,559	(4,631)	(3,238)	2,503	(735)
Other income (expenses):						
Interest expense	(4,508)	(2,602)(d)(f)	(7,110)	(5,406)	(2,703)(d)(f)	(8,109)
Net income (loss)	$ (11,698)	$ (43)	$ (11,741)	$ (8,644)	$ (200)	$ (8,844)
General partner s interest in net income (loss)	(233)	(1)	(234)	(173)	(4)	(177)
Limited partners interest in net income (loss)	$ (11,465)	$ (42)	$ (11,507)	$ (8,471)	$ (196)	$ (8,667)
Limited partners net income (loss) per unit	$ (1.64)	$ (0.01)	$ (1.65)	$ (1.66)	$ (0.04)	$ (1.70)
Weighted average number of units used in computation of limited partners net income (loss) per unit	6,997	6,997	6,997	5,099	5,099	5,099

Pro forma adjustments:

(a) Assumes the value of allocated in-kind revenues from the beginning of the period.
(b) Assumes allocated Plant direct operating costs and administrative fees from the beginning of the period.
(c) Assumes depreciation expense from the beginning of the period, calculated on a straight-line basis over a 40 year useful life.
(d) Assumes interest expense from the beginning of the period at the Partnership s weighted average interest rate of 7.21% for the ten months ended October 31, 2011 and 7.48% for the year ended December 31, 2010.
(e) Assumes a gain on purchase resulting from the difference between the cash consideration paid of $35.5 million and the fair value of the Interest of $36.1 million.
(f) Assumes the straight-line amortization additional debt issuance costs over the remaining life of the credit facility, or 57 months, from the beginning of the period.
(g) Elimination of bargain purchase gain which was assumed to have occurred at the beginning of the period presented.

Enbridge Assets

Effective November 1, 2009, American Midstream, LLC, a wholly owned subsidiary, acquired certain pipeline assets from Enbridge Midcoast Energy, LP, for an aggregate purchase price of $158.0 million. Prior to the acquisition, we had no operating tangible assets.

The acquired businesses were renamed as follows:

American Midstream (Alabama Intrastate), LLC

American Midstream (Bamagas Intrastate), LLC

American Midstream (Tennessee River), LLC

American Midstream (Mississippi), LLC

American Midstream (Midla), LLC

American Midstream (Alabama Gathering), LLC

American Midstream (AlaTenn), LLC

American Midstream Onshore Pipelines, LLC

Mid Louisiana Gas Transmission, LLC

American Midstream Offshore (Seacrest), LP

American Midstream (SIGCO Intrastate), LLC

American Midstream (Louisiana Intrastate), LLC

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

The acquisition qualifies as a business combination and, and as such we estimated the fair value of each property as of the acquisition date (the date on which we obtained control of the properties). The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. We used a discounted cash flow model and made market assumptions as to future commodity prices, expectations for timing and amount of future development and operating costs, projections of future rates of production, and risk adjusted discount rates. These assumptions represent Level 3 inputs.

The following table summarizes the consideration paid to the seller and the amounts of assets acquired and liabilities assumed in the acquisition:

	(in thousands)
Consideration paid to seller	
Cash consideration	$ 150,818
Recognized amounts of identifiable assets acquired and liabilities assumed	
Property, plant and equipment	$ 151,085
Other post-retirement benefit plan assets, net	394
Other liabilities assumed	(661)
Total identifiable net assets	$ 150,818

Acquisition costs of $0.3 million and $6.4 million have been recorded in the statements of operations under the caption Transaction expenses for the year ended December 31, 2010 and the period ended December 31, 2009, respectively.

3. Concentration of Credit Risk and Trade Accounts Receivable

Our primary market areas are located in the United States along the Gulf Coast and in the Southeast. We have as concentration of trade receivable balances due from companies engaged in the production, trading, distribution and marketing of natural gas and NGL products. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Our customers historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable; however, for the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, no allowances on or write-offs of accounts receivable were recorded.

Enbridge Marketing (US) L.P., ConocoPhillips Corporation, Dow Chemical and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue in the consolidated statement of operations in one or more of the periods presented, accounting for $44.8 million, $100.7 million, $15.7 million and $38.0 million, respectively, for the year ended December 31, 2011, $63.9 million, $53.4 million, $16.4 million and $22.9 million, respectively, for year ended December 31, 2010 and $17.8 million, $5.0 million, $3.1 million and $0.1 million, respectively, for the period ended December 31, 2009.

4. Other Current Assets

	December 31, 2011	December 31, 2010
	(in thousands)	
Other receivables	$ 663	$ 30
Construction, operating and maintenance agreement (COMA)	623	

Prepaid insurance current portion	567	767
Other prepaid amounts	508	608
Gas imbalances receivable	852	
NGL inventory	96	101
Other current assets	14	17
	$ 3,323	$ 1,523

For the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, we recorded no LCM write-downs on our inventory.

5. Derivatives

Commodity derivatives

To minimize the effect of a downturn in commodity prices and protect our profitability and the economics of our development plans, we enter into commodity economic hedge contracts from time to time. The terms of the contracts depend on various factors, including management s view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to moderate the effects of a severe commodity price downturn while allowing us to participate in some commodity price increases. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level some form of commodity hedging is appropriate in accordance with policies which are established by the board of directors of our general partner. Currently, the commodity hedges are in the form of swaps and puts.

In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from cancelling our then-existing NGL swap contracts and entering into new NGL swap contracts with an existing counterparty that extend through the end of 2012. A $3.0 million realized loss resulting from the early termination of these swap contracts was recorded in the consolidated statement of operations for year ended December 31, 2011.

We may be required to post collateral with our counterparty in connection with our derivative positions. As of December 31, 2011, we had no posted collateral with our counterparty. The counterparty is not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparty allowing us to offset our commodity derivative asset and liability positions.

As of December 31, 2011, the aggregate notional volume of our commodity derivatives was 11.4 million NGL gallons.

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

As of December 31, 2011 and 2010, the fair value associated with our derivative instruments were recorded in our consolidated balance sheets, under the caption Risk management assets and Risk management liabilities, as follows:

	December 31,	
	2011	**2010**
	(in thousands)	
Risk management assets:		
Commodity derivatives	$ 456	$
Risk management liabilities:		
Commodity derivatives	$ 635	$

For the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, we recorded the following realized and unrealized mark-to-market (losses):

	Period from August 20, 2009 (Inception Date)	**Predecessor Ten Months**

	Year Ended December 31, 2011	2010	to December 31, 2009	ended October 31, 2009
	(in thousands)			
Commodity derivatives	$ (849)	$ (308)	$	$
Interest rate derivatives		(77)	(5)	
	$ (849)	$ (385)	$ (5)	$

Fair Value Measurements

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

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

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	(in thousands)			
Fair value asset (liability), beginning of period	$	$ 77	$	$
Realized gain (loss) on early termination of commodity derivatives	(2,998)			
Realized (loss) on expiration of commodity put Contract	(308)			
Unrealized gain (loss) on commodity derivatives	(541)	(308)		
Unrealized gain (loss) on interest rate caps		(77)	(5)	
Purchases	670	308	82	
Settlements	2,998			
Fair value asset (liability), end of period	$ (179)	$	$ 77	$

Also included in revenue were ($1.6) million and $nil million in realized gains (losses) for the years ended December 31, 2011 and 2010, respectively, representing our monthly swap settlements. No such gains (losses) were recorded for the periods ended December 31, 2009 and October 31, 2009.

6. Property, Plant and Equipment, Net

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

	Useful Life	December 31, 2011	December 31, 2010
		(in thousands)	
Land		$ 41	$ 41
Buildings and improvements	4 to 40	1,490	1,467
Processing and treating plants	8 to 40	49,396	13,010
Pipelines	5 to 40	149,040	143,805
Compressors	4 to 20	8,154	7,163
Equipment	8 to 20	1,580	1,711
Computer software	5	1,529	1,390
Total property, plant and equipment		211,230	168,587
Accumulated depreciation		(40,999)	(21,779)
Property, plant and equipment, net		$ 170,231	$ 146,808

Of the gross property, plant and equipment balances at December 31, 2011 and 2010, $24.0 million and $24.3 million, respectively, was related to AlaTenn and Midla, our FERC regulated interstate assets.

7. Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically, we record an ARO at the time the assets are installed or acquired if a reasonable estimate of fair value can then be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for an ARO when assets are taken out of service or otherwise abandoned.

During the years ended December 31, 2011 and 2010, we recognized $0.9 million and $6.1 million, respectively, of ARO which is included in other liabilities for specific assets that we intend to retire for operational purposes.

We recorded accretion expense, which is included in depreciation expense, in our consolidated statements of operations of $1.4 million, $1.2 million, $nil and $0.1 million for the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, respectively, in our consolidated statements of operations related to these AROs.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

No assets were legally restricted for purposes of settling our ARO liabilities during the years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009. The following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for years ended December 31, 2011 and 2010 and the periods ended December 31, 2009 and October 31, 2009, respectively:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	(in thousands)			
Balance at beginning of period	$ 7,249	$	$	$ 2,006
Additions	872	6,058		
Reductions	(920)			
Expenditures	(501)			
Accretion expense	1,393	1,191		108
Balance at end of period	$ 8,093	$ 7,249	$	$ 2,114

In August 2011, we sold an abandoned portion of pipe for which we had recorded an ARO. As a result of this sale, we are no longer responsible for the costs of abandonment on this pipe and have reduced our ARO during 2011 by $0.5 million during 2011. In December 2011, we completed the abandonment of the West Cameron Pipeline at a cost of $0.5 million. Upon the completion of this project we reduced our ARO by $0.4 million.

8. Other Assets, Net

Other assets, net were as follows:

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred financing costs	$ 2,545	$ 1,338
Other post retirement benefit plan assets, net	966	450
Prepaid amounts long term	139	140
Security deposits	57	57
	$ 3,707	$ 1,985

Deferred financing costs

During the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, deferred financing costs related to the term loan portion of our credit facility were amortized using the effective interest rate over the term of the term credit facility which was retired on August 1, 2011. See Note 12 for more information about our credit facility. Deferred financing costs related to the revolver portion of our credit facility are amortized on a straight-line basis over the term of the credit facility. During the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, we recorded deferred financing costs of $1.3 million, $2.2 million and $0.1 million, respectively.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

9. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities were as follows:

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred revenue short term	$ 2,314	$ 210
Accrued salaries	1,542	957
Accrued expenses	953	839
Construction operating and maintenance agreement deposits	710	
Gas imbalances payable	1,200	
Contract obligations short term	240	240
Accrued interest payable	123	407
Other	4	23
	$ 7,086	$ 2,676

10. Other Liabilities

Other liabilities were as follows:

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred revenue long term	$ 351	$ 528
Asset retirement obligations	8,093	7,249
Contract obligations long term	88	208
Other deferred expenses	80	93
	$ 8,612	$ 8,078

11. Other Loan

Other loan represents insurance premium financing in the original amounts of $0.8 million bearing interest at 4.25 % per annum, which was repayable in equal monthly installments of less than $0.1 million through October 1, 2011.

12. Long-Term Debt

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

That credit facility provided for a maximum borrowing equal to the lesser of (i) $85 million less required amortization of term loan payments and (ii) 3.50 times adjusted consolidated EBITDA. We could have elected to have the loans under this credit facility bear interest at either (i) 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 paid a facility fee of 1.0% per annum. In December 2009 we entered into an interest rate cap with participating lenders that effectively caped our Eurodollar-based rate exposure on that portion of our debt at 4.0%. The interest rate caps expired in December 2011. Prior to our initial public offering the weighted average interest rate on borrowings under our old credit facility was approximately 7.66%, 7.48% and 5.79% for the 7 months ended July 31, 2011 (date of termination), the year ended December 31, 2010 and the period ended December 31, 2009, respectively.

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

The new credit facility provides for a maximum borrowing equal to the lesser of (i) $100 million or (ii) 4.50 times adjusted consolidated EBITDA. We may elect to have loans under the new credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.25% to 3.50% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 1/2 of 1% (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its prime rate , and (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.25% to 2.50% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan. Following our initial public offering the weighted average interest rate on borrowings under our new credit facility was 4.65% for the 5 months ended December 31, 2011. The blended weighted average interest rate for the year ended December 31, 2011 was 6.71%.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

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

The new credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are (i) a total leverage ratio test (not to exceed 4.50 times) and a minimum interest coverage ratio test (not less than 2.50 times). We were in compliance with all of the covenants under our credit facility as of December 31, 2011.

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Term loan facility	$	$ 45,000
Revolving loan facility	66,270	11,370
	66,270	56,370
Less: current portion		6,000
	$ 66,270	$ 50,370

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

In connection with our new credit facility and amendments thereto, we incurred $2.5 million in debt issuance costs which are being amortized on a straight-line basis over the term of the new credit facility. In addition, we recognized a $0.6 million loss upon the early termination of our old credit facility which has been included in interest expense in our consolidated statement of operations.

13. Partners Capital

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

On August 1, 2011, we closed our initial public offering (the IPO) of our 3,750,000 common units at an offering price of $21 per unit. After deducting underwriting discounts and commissions of $4.9 million paid to the underwriters, offering expenses of $4.2 million and a structuring fee of $0.6 million, the net proceeds from our initial public offering were $69.1 million. We used all of the net offering proceeds from our initial public offering for the uses described in the Prospectus.

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

each common unit held by AIM Midstream Holdings reverse split into 0.485 common units, resulting in the ownership by AIM Midstream Holdings of an aggregate of 5,327,205 common units, representing an aggregate 97.1% limited partner interest in us;

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

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

each common unit held by participants in our general partner s long term incentive plan (the LTIP), reverse split into 0.485 common units, resulting in their ownership of an aggregate of 50,946 common units, representing an aggregate 0.9% limited partner interest in us; and

each outstanding phantom unit granted to participants in our LTIP reverse split into 0.485 phantom units, resulting in their holding an aggregate of 209,824 phantom units.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

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

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

The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution.

The subordination period generally will end and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $1.65 on each outstanding common and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after September 30, 2014.

The subordination period will automatically terminate and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $2.475 (150% of the annualized minimum quarterly distribution) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 2.0% interest and incentive distribution rights for any four consecutive quarter period ending on or after September 30, 2012; provided that we have paid at least the minimum quarterly distribution from operating surplus on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each quarter in that four-quarter period.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest if we issue additional units. Our general partner s 2.0% interest, and the percentage of our cash distributions to which it is entitled from such 2.0% interest, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest. Our partnership agreement does not require that our general partner fund its capital contribution with cash. It may instead fund its capital contribution by the contribution to us of common units or other property.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following discussion assumes that our general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

first, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives a total of $0.47438 per unit for that quarter (the first target distribution);

second, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $0.51563 per unit for that quarter (the second target distribution);

third, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $0.61875 per unit for that quarter (the third target distribution); and

thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

Distributions

We made distributions of $9.8 million and $11.8 million for years ended December 31, 2011 and 2010, respectively. No distributions were made during the period ended December 31, 2009. We made no distributions in respect of our general partner s incentive distribution rights during any of the periods presented. We have neither adopted a policy nor were we required to make minimum distributions during the periods presented in these financial statements.

In addition to the distributions described above, in August 2011 we made a special distribution of $33.7 million to AIM Midstream Holdings, participants in our LTIP holding common units and our general partner as described in the Prospectus.

The number of units outstanding was as follows:

	December 31,	
	2011	**2010**
	(in thousands)	
Limited partner common units	4,561	5,363
Limited partner subordinated units	4,526	
General partner units	185	109

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

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

14. Long-Term Incentive Plan

Our general partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our general partner adopted an LTIP for its employees, consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our general partner adopted an amended and restated LTIP. The LTIP currently permits the grant of awards that include phantom units that typically vest ratably over four years and may also include distribution equivalent rights (DER s), covering an aggregate of 303,601 of our units. A DER entitles the grantee to a cash payment equal to the cash distribution made by us with respect to a unit during the period such DER is outstanding. At December 31, 2011 and 2010, 54,827 and 62,246 units, respectively, were available for future grant under the LTIP giving retroactive treatment to the reverse unit split described in Note 13 Partners Capital .

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

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

Prior to our initial public offering, the fair value of the grants issued was calculated by the general partner based on several valuation models, including: a 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:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009
		(in thousands)	
Outstanding at beginning of period	205,864	175,236	
Granted	19,414	74,437	175,236
Vested	(62,418)	(43,809)	
Outstanding at end of period	162,860	205,864	175,236
Fair value per unit	$ 14.70 to $19.69	$ 14.70 to $16.15	$ 16.15

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our units at the grant date. Compensation costs related to these awards including amortization, modification costs, DER payments and the cost of the DER buy-out for the years ended December, 2011 and 2010 and the period ended December 31, 2009 was $3.4 million, $1.7 million and $0.2 million, respectively, which is classified as equity compensation expense in the consolidated statement of operations and the non-cash portion in partners capital on the consolidated balance sheet.

In June 2011, certain existing LTIP grant agreements were modified to exclude the DER provision in exchange for a cash payment of $1.5 million which has been included in equity compensation expense in the consolidated statement of operations. The total fair value of vesting units at the time of vesting was $1.2 million and $0.9 million for the years ending December 31, 2011 and 2010, respectively. No units vested during the period ended December 31, 2009.

The total compensation cost related to unvested awards not yet recognized at December 31, 2011 and 2010 was $2.7 million and $3.8 million, respectively, and the weighted average period over which this cost is expected to be recognized as of December 31, 2011 is approximately 2.1 years.

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

15. Post-Employment Benefits

As a result of our acquisition from Enbridge, the sponsorship of the AlaTenn VEBA plans were transferred from Enbridge to us effective November 1, 2009. Accordingly, we sponsor a contributory postretirement plan that provides medical, dental and life insurance benefits for qualifying U.S. retired employees (referred to as the OPEB Plan).

The tables below detail the changes in the benefit obligation, the fair value of the plan assets and the recorded asset or liability of the OPEB Plan using the accrual method.

	OPEB Plan			
	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009	Predecessor Ten Months ended October 31, 2009
	(in thousands)			
Change in benefit obligation				
Obligation, beginning of period	$ 869	$ 734	$	$ 741
Obligation assumed from the acquisition from Enbridge			771	
Service cost	3	10	2	8
Interest cost	22	43	7	36
Actuarial (gain) loss	(367)	112	(44)	10
Benefits paid	(61)	(30)	(2)	(24)
Benefit obligation, ending	$ 466	$ 869	$ 734	$ 771
Change in plan assets				
Fair value of plan assets, beginning of period	$ 1,319	$ 1,174	$	$ 999
Plan assets acquired from Enbridge			1,165	
Actual return on plan assets	99	61	11	122
Employer s contributions	90	113		68
Benefits paid	(76)	(29)	(2)	(24)
Fair value of plan assets, ending	$ 1,432	$ 1,319	$ 1,174	$ 1,165
Funded status				
Funded status	$ 966	$ 450	$ 440	$ 257

The amounts of plan assets recognized in our consolidated balance sheets were as follows:

	OPEB Plan December 31, 2011	OPEB Plan December 31, 2010
	(in thousands)	
Other assets	$ 966	$ 450

	$ 966	$ 450

The amounts included in accumulated other comprehensive income at December 31, 2011 and 2010 that have not been recognized as components of net periodic benefit expense are $0.4 million and $0.1 million, respectively, which relate to net gains.

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Notes to Consolidated Financial Statements (continued)

Components of Net Periodic Benefit Cost and Other amounts Recognized in Other Comprehensive Income

	OPEB Plan December 31,	
	2011	2010
	(in thousands)	
Net Periodic (Benefit) Cost		
Service cost	$ 3	$ 10
Interest cost	22	43
Expected return on plan assets	(60)	(53)
Amortization of net (gain) loss	(47)	
Net periodic (benefit) cost	$ (82)	$
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Net loss (gain)	(359)	(10)
Total recognized in other comprehensive income	(359)	(10)
Total recognized in net periodic benefit cost and other comprehensive income	$ (441)	$ (10)

The estimated net gain that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is less than $0.1 million.

Economic assumptions

The assumptions made in measurement of the projected benefit obligations or assets of the OPEB Plan were as follows:

	OPEB Plan		
	2011	2010	2009
Discount rate	3.96%	5.50%	6.00%
Expected return on plan assets	4.50%	4.50%	4.50%

A one percent increase in the assumed medical and dental care trend rate would result in an increase of less than $0.1 million in the accumulated post-employment benefit obligations. A one percent decrease in the assumed medical and dental care trend rate would result in a decrease of less than $0.1 million in the accumulated post-employment benefit obligations.

The above table reflects the expected long-term rates of return on assets of the OPEB Plan on a weighted-average basis. The overall expected rates of return are based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations. We believe this rate approximates the return we will achieve over the long-term on the assets of our plans. Historically, we have used a discount rate that corresponds to one or more high quality corporate bond indices as an estimate of our expected long-term rate of return on plan assets for our OPEB Plan assets. For 2011, 2010 and 2009 we selected the discount rate using the Citigroup Pension Discount Curve, or CPDC. The CPDC spot rates represent the equivalent yield on high-quality, zero-coupon bonds for specific maturities. These rates are used to develop a single, equivalent discount rate based on the OPEB Plan s expected future cash flows.

Expected future benefit payments

The following table presents the benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five years thereafter by the OPEB Plan:

	Gross Benefit Payments OPEB Plan (in thousands)
For the year ending	
2012	$ 40
2013	39
2014	34
2015	33
2016	31
Five years thereafter	133

The expected future benefit payments are based upon the same assumptions used to measure the projected benefit obligations of the OPEB Plan including benefits associated with future employee service.

Future contributions to the Plans

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

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Plan assets

The weighted average asset allocation of our OPEB Plan at the measurement date by asset category, which are all classified as Level 1 investments, are as follows:

	OPEB Plan		
	2011	**2010**	**2009**
Fixed income (a)	72.1%	70.7%	76.7%
Cash and short term assets (b)	27.9%	29.3%	23.3%
Total	100.0%	100.0%	100.0%

(a) United States government securities, municipal corporate bonds and notes and asset backed securities
(b) Cash and securities with maturities of one year or less

16. Commitments and Contingencies

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Commitments and contractual obligations

Future non-cancelable commitments related to certain contractual obligations as of December 31, 2011 are presented below:

	Payments Due by Period (in thousands)						
	Total	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
Operating leases and service contract	$ 1,774	$ 415	$ 361	$ 377	$ 367	$ 131	$ 123
ARO	8,093					8,093	
Total	$ 9,867	$ 415	$ 361	$ 377	$ 367	$ 8,224	$ 123

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

	Year Ended	Period from August 20, 2009 (Inception Date) to

	December 31, 2011	December 31, 2010	December 31, 2009
	(in thousands)		
Operating leases	$ 803	$ 757	$ 60
ARO	1,393	1,191	
	$ 2,196	$ 1,948	$ 60

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.

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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.

17. 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 years ended December 31, 2011 and 2010 and the period ended December 31, 2009 administrative and operational services expenses of $9.6 million, $7.6 million and $1.1 million, respectively, were charged to us by our general partner.

Prior to our IPO, we had entered into an advisory services agreement with American Infrastructure MLP Management, L.L.C., American Infrastructure MLP PE Management, L.L.C., and American Infrastructure MLP Associates Management, L.L.C., as the advisors. The agreement provided for the payment of $0.3 million in 2010 and annual fees of $0.3 million plus annual increases in proportion to the increase in budgeted gross revenues thereafter. In exchange, the advisors agreed to provide us services in obtaining equity, debt, lease and acquisition financing, as well as providing other financial, advisory and consulting services. For the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, $0.2 million, $0.3 million and less than $0.1 million had been recorded to selling, general and administrative expenses under this agreement.

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

Predecessor Related Party Transactions

The Predecessor was wholly owned by Enbridge Midcoast Energy, L.P. (Enbridge) and its subsidiaries. For the ten months ended October 31, 2009, the Predecessor received contributions by Enbridge of $111.1 million and paid distributions to the Predecessor s parent of $25.8 million.

Enbridge allocated certain overhead costs associated with general and administrative services, including executive management, accounting, information services, engineering, and human resources support to the Predecessor. These overhead costs were $6.7 million for the period ended October 31, 2009 and were allocated based primarily on a percentage of revenue, which we believe is reasonable. The Predecessor recorded operating revenues to Enbridge affiliates for natural gas gathering, treating, processing, marketing and transportation services of $73.9 million for the period ended October 31, 2009. The Predecessor also purchased natural gas from Enbridge affiliates for sale to third-parties at market prices on the date of purchase of $0.9 million for the period ended October 31, 2009.

Additionally, for the ten months ended October 31, 2009, the Predecessor had interest income of $0.4 million and interest expense of $4.1 million related to financing transactions with affiliates.

18. Reporting Segments

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

Gathering and Processing

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

Transmission

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

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

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Notes to Consolidated Financial Statements (continued)

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

	Gathering and Processing	Transmission	Total
Year ended December 31, 2011			
Revenue	$ 181,517	$ 66,765	$ 248,282
Segment gross margin (a),(b)	32,450	13,737	46,187
Realized gain (loss) on early termination of commodity derivatives	(2,998)		(2,998)
Realized (loss) on expiration of commodity put contracts	(308)		(308)
Unrealized gain (loss) on commodity derivatives	(541)		(541)
Direct operating expenses			12,856
Selling, general and administrative expenses			10,794
Advisory services agreement termination fee			2,500
Transaction expenses			282
Equity compensation expense			3,357
Depreciation expense			20,705
Gain (loss) on acquisition of assets			565
Gain (loss) on sale of assets, net			399
Interest expense			4,508
Net income (loss)			(11,698)

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Notes to Consolidated Financial Statements (continued)

	Gathering and Processing	Transmission	Total
Year ended December 31, 2010			
Revenue	$ 158,455	$ 53,485	$ 211,940
Segment gross margin (a),(b)	24,595	13,524	38,119
Realized gain (loss) on early termination of commodity derivatives			
Unrealized gain (loss) on commodity derivatives			
Direct operating expenses			12,187
Selling, general and administrative expenses			7,120
Advisory services agreement termination fee			
Transaction expenses			303
Equity compensation expense			1,734
Depreciation expense			20,013
Gain (loss) on acquisition of assets			
Gain (loss) on sale of assets, net			
Interest expense			5,406
Net income (loss)			(8,644)

	Gathering and Processing	Transmission	Total
Period from August 9, 2009 (inception date) to December 31, 2009			
Revenue	$ 27,857	$ 4,976	$ 32,833
Segment gross margin (a)	3,698	2,542	6,240
Realized gain (loss) on early termination of commodity derivatives			
Unrealized gain (loss) on commodity derivatives			
Direct operating expenses			1,594
Selling, general and administrative expenses			1,196
Advisory services agreement termination fee			
Transaction expenses			6,404
Equity compensation expense			150
Depreciation expense			2,978
Gain (loss) on acquisition of assets			
Gain (loss) on sale of assets, net			
Interest expense			910
Net income (loss)			(6,992)

American Midstream Partner s LP and Subsidiaries

Notes to Consolidated Financial Statements (continued)

	Gathering and Processing	Transmission	Total
Ten months ended October 31, 2009 (Predecessor)			
Revenue	$ 132,957	$ 10,175	$ 143,132
Segment gross margin (a)	20,024	9,881	29,905
Realized gain (loss) on early termination of commodity derivatives			
Unrealized gain (loss) on commodity derivatives			
Direct operating expenses			10,331
Selling, general and administrative expenses			8,553
Advisory services agreement termination fee			
Transaction expenses			
Equity compensation expense			
Depreciation expense			12,630
Gain (loss) on acquisition of assets			
Gain (loss) on sale of assets, net			
Interest expense			3,728
Net income (loss)			$ (5,337)

(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 year ended December 31, 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 year ended December 31, 2011, $0.5 million in unrealized gains (losses) on commodity derivatives were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized early termination costs on commodity derivatives. For the year ended December 31, 2011, ($3.0) million in realized gains (losses) on the early termination of commodity derivatives were excluded from our Gathering and Processing segment gross margin.

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

For the purposes of our Gathering and Processing segment, for the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented significant customers, each representing more than 10% of our segment revenue in our Gathering and Processing segment. Our segment revenue derived from Enbridge Marketing (US) L.P., ConocoPhillips Corporation and Dow Hydrocarbons and Resources represented $29.9 million, $100.7 million and $15.7 million of segment revenue for the year ended December 31, 2011, $47.3 million, $53.4 million and $16.4 million of segment revenue for the year ended December 31, 2010 and $14.7 million, $5.0 million and $3.1 million of segment revenue for the period ended December 31, 2009, respectively.

For purposes of our Transmission segment, for the years ended December 31, 2011 and 2010 and the period ended December 31, 2009, 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 in one or more of the periods presented. Our segment revenue derived from Enbridge Marketing (US) L.P. ExxonMobil Corporation and Calpine Corporation represented $15.0 million, $38.0 and $5.1 million of segment revenue for the year ended December 31, 2011, $16.6 million, $22.9 million and $5.1 million of segment revenue for the year ended December 31, 2010 and $3.0 million, $0.1 million and $0.9 million of segment revenue for the period ended December 31, 2009, respectively.

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

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

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Notes to Consolidated Financial Statements (continued)

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

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

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

We determined basic and diluted net income (loss) per general partner unit and limited partner unit as follows, in thousands except per unit amounts:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to December 31, 2009
Net (loss) attributable to general partner and limited partners	$ (11,698)	$ (8,644)	$ (6,992)
Weighted average general partner and limited partner units outstanding(a)(b)	7,137	5,199	2,231
General partner and limited partner (loss) per unit (basic and diluted)	$ (1.64)	$ (1.66)	$ (3.13)
Net (loss) attributable to limited partners	$ (11,465)	$ (8,471)	$ (6,852)
Weighted average limited partner units outstanding(a)(b)	6,997	5,099	2,187
Limited partners net (loss) per unit (basic and diluted)	(1.64)	$ (1.66)	$ (3.13)
Net (loss) attributable to general partner	$ (233)	$ (173)	$ (140)
Weighted average general partner units outstanding	140	99	43
General partner net (loss) per unit (basic and diluted)	$ (1.66)	$ (1.75)	$ (3.26)

(a) Includes unvested phantom units with DERs, which are considered participating securities, of 205,864 and 175,236 as of December 31, 2010 and 2009, respectively. The DER s were eliminated on June 9, 2011. There were no such unvested phantom units with DERs at December 31, 2011.

(b) Gives effect to the reverse unit split as described in Note 13, Partners Capital .

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20. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2011 and 2010 are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
		(in thousands expect per unit amounts)			
Year ended December 31, 2011					
Revenues	$ 63,765	$ 65,634	$ 57,958	$ 57,386	$ 244,743
Gross margin (a)	12,312	10,617	9,646	13,612	46,187
Operating income (loss)	(2,246)	(2,901)	(3,375)	1,332	(7,190)
Net income (loss)	$ (3,510)	$ (4,182)	$ (4,167)	$ 161	$ (11,698)
General partner s interest in net income (loss)	(70)	(84)	(83)	4	(233)
Limited partners interest in net income (loss)	$ (3,440)	$ (4,098)	$ (4,084)	$ 157	$ (11,465)
Limited partners net income (loss) per unit	$ (0.62)	$ (0.74)	$ (0.53)	$ 0.02	$ (1.64)
Year ended December 31, 2010					
Revenues	$ 54,712	$ 47,790	$ 52,953	$ 56,485	$ 211,940
Gross margin (a)	9,748	8,947	8,437	10,987	38,119
Operating income (loss)	(97)	(1,478)	(1,941)	278	(3,238)
Net income (loss)	$ (1,454)	$ (2,853)	$ (3,360)	$ (977)	$ (8,644)
General partner s interest in net income (loss)	(29)	(57)	(67)	(20)	(173)
Limited partners interest in net income (loss)	$ (1,425)	$ (2,796)	$ (3,293)	$ (957)	$ (8,471)
Limited partners net income (loss) per unit	$ (0.29)	$ (0.56)	$ (0.66)	$ (0.18)	$ (1.66)

(a) For a definition of gross margin and a reconciliation to its mostly directly comparable financial measure calculated and presented in accordance with GAAP, please read note Note 18, Reporting Segments.

21. Subsequent Event

On January 24, 2012, we announced a distribution of $0.4325 per unit payable on February 10, 2012 to unitholders of record on February 3, 2012.