American Midstream Partners, LP
Form 10-K
March 11, 2014

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

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

Or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-35257

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

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of incorporation or organization) | 27-0855785<br>(I.R.S. Employer Identification No.) |
| 1400 16th Street, Suite 310<br>Denver, CO<br>(Address of principal executive offices) | 80202<br>(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 on Which Registered |
|---|---|
| Common Units Representing Limited Partnership Interests | 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 o 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 o 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 o

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 o

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. o

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 28, 2013, was $83,928,303. The aggregate market value was computed by reference to the last sale price of the registrant’s common units on the New York Stock Exchange on June 28, 2013.

There were 11,097,144 common units, 5,353,970 Series A Units and 1,168,225 Series B PIK Units of American Midstream Partners, LP outstanding as of March 7, 2014. Our common units trade on the New York Stock Exchange under the ticker symbol “AMID.”

Documents Incorporated by Reference

None.

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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," "f other similar words.

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

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

- our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems;
- the demand for NGL products by the petrochemical, refining or other industries;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects and the successful integration and future performance of such assets;
- our ability to hire as well as retain qualified personnel to execute our business strategy;
- volatility in the price of our common units;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- our ability to timely and successfully integrate our current and future acquisitions, including the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance; and
- general economic, market and business conditions.

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

GLOSSARY OF TERMS

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

| | |
|---|---|
| Bbl | Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit. |
| Bbl/d | Barrels per day. |
| Bcf | Billion cubic feet. |
| Btu | British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. |
| Condensate | Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing. |
| /d | Per day. |
| FERC | Federal Energy Regulatory Commission. |
| Fractionation | Process by which natural gas liquids are separated into individual components. |
| Gal | Gallons. |
| MBbl | Thousand barrels. |
| MMBbl | Million barrels. |
| MMBbl/d | Million barrels per day. |
| MMBtu | Million British thermal units. |
| Mcf | Thousand cubic feet. |
| MMcf | Million cubic feet. |
| NGL or NGLs | Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature. |
| Tcf | Trillion cubic feet. |
| Throughput | The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period. |

As used in this 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.

PART I
Item 1. Business
Overview
American Midstream Partners, LP (along with its consolidated subsidiaries, “we,” “us,” “our,” or the “Partnership”) is a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We are engaged in the business of gathering, treating, processing, fractionating and transporting natural gas through our ownership and operation of eleven gathering systems, two processing facilities, one fractionation facility, four terminal sites, three interstate pipelines and five intrastate pipelines. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Recently, we became an owner, developer and operator of petroleum, agricultural, and chemical liquid terminal storage facilities. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas and NGL markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 2,100 miles of pipelines that gather and transport approximately 1 Bcf/d of natural gas and operate approximately 1.3 million barrels of above-ground storage capacity across four marine terminal sites.

On April 15, 2013, the Partnership, American Midstream GP, LLC, which we refer to as our general partner, and AIM Midstream Holdings, LLC (“AIM Midstream Holdings”), an affiliate of American Infrastructure MLP Fund, entered into and consummated agreements (the "ArcLight Transactions") with High Point Infrastructure Partners, LLC ("HPIP"), an affiliate of ArcLight Capital Partners, LLC (“ArcLight”), pursuant to which HPIP (i) acquired 90% of our general partner and all of our subordinated units from AIM Midstream Holdings and (ii) contributed certain midstream assets and $15 million in cash to us in exchange for 5,142,857 convertible preferred units (the “Series A Preferred Units”) issued by the Partnership. As a result of these transactions, HPIP acquired both control of our general partner, which holds all of our general partner units and incentive distribution rights, and currently holds 36.5% of our outstanding limited partnership interests. The midstream assets contributed by HPIP consist of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. These midstream assets, commonly referred to as the High Point System, gather natural gas from both onshore and offshore producing regions around southeast Louisiana. The onshore footprint is located in Plaquemines and St. Bernard Parish, Louisiana. The offshore footprint consists of the following federal Gulf of Mexico zones: Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound. Natural gas is collected at more than 75 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on oil and liquids-rich reservoirs. The High Point System is comprised of FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. The High Point System delivers the natural gas to the Toca Gas Processing Plant, operated by Enterprise Products Partners, LP (“Enterprise”), where the products are processed and the residue gas sent to an unaffiliated interstate system owned by Kinder Morgan.

Effective August 9, 2013, the Partnership executed an equity restructuring agreement ("Equity Restructuring") with our general partner and HPIP. As part of the Equity Restructuring, the Partnership's 4,526,066 subordinated units and previous incentive distribution rights (the “former IDRs”) were combined into and restructured as a new class of incentive distribution rights (the “new IDRs”). Upon the issuance of the new IDRs, the subordinated units and former IDRs were cancelled. The new IDRs were allocated 85.02% to HPIP and 14.98% to our general partner. The new IDRs entitle the holders of our incentive distribution rights to receive 48% of any quarterly cash distributions from available cash after the Partnership's common unitholders have received the full minimum quarterly distribution ($0.4125 per unit) for each quarter plus any arrearages from prior quarters (of which there are currently none). The Equity Restructuring also provided for the issuance of warrants to our General Partner to purchase up to 300,000 of our common units at an exercise price of $0.01 per common unit.

Following the announcement of the Equity Restructuring, AIM Midstream Holdings filed an action in Delaware Chancery Court against HPIP, our general partner and us seeking either rescission of the Equity Restructuring or, in the alternative, monetary damages. As a result of the action filed by AIM Midstream Holdings, the warrants that were issued by the Partnership, in conjunction with the Equity Restructuring, to the general partner for subsequent conveyance to AIM Midstream Holdings were cancelled effective August 29, 2013. Also as a consequence of the action filed by AIM Midstream Holdings, the escrowed funds of $12.5 million were not released to the Partnership. On September 30, 2013, HPIP contributed $12.5 million in cash to the Partnership, which was used to satisfy obligations under our credit agreement and was accounted for as a contribution from our general partner.

On February 5, 2014, HPIP, the Partnership and our general partner entered into a settlement (the “Settlement”) with AIM Midstream Holdings regarding the action filed in Delaware Chancery Court by AIM Midstream Holdings. Under the Settlement, among other things:

- HPIP and AIM Midstream Holdings amended the limited liability company agreement of our General Partner (the "LLC Amendment") to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP's sharing percentage is now 95% and AIM Midstream Holdings's Sharing Percentage is 5%;

- HPIP transferred all of the 85.02% of the Partnership's outstanding new IDRs held by HPIP to the General Partner such that the General Partner owns 100% of the outstanding new IDRs; and

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

Our operations are organized into three segments: (i) Gathering and Processing, (ii) Transmission and (iii) Terminals. 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 two processing facilities that collectively produced an average of approximately 39.9 Mgal/d and 37.0 Mgal/d of gross NGLs for the years ended December 31, 2013 and 2012, respectively.

In our Transmission segment, we receive fee-based and fixed-margin compensation 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.

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

Recent Acquisitions

On December 17, 2013, we completed the acquisition of Blackwater Midstream Holdings, LLC, an owner, developer and operator of petroleum, agricultural, and chemical liquid terminal storage facilities. Blackwater owns and operates 1.3 million barrels of storage capacity across four terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland. These terminal sites provide storage services to support various commercial customers, including commodity brokers, refiners, and chemical manufacturers, to store a range of products, including crude oil, bunker fuel, distillates, chemicals and agricultural products. We refer to the agreement and plan of merger related to the Blackwater Acquisition as the Blackwater Merger Agreement.

On January 31, 2014, we completed the PVA Asset Acquisition pursuant to the PVA Asset Purchase Agreement and acquired approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The consideration for the PVA Asset Acquisition was financed with the net proceeds of the Partnership's recent equity offering and the issuance to our general partner of 1,168,225 Series B PIK Units (the "Series B PIK Units") representing series B limited partnership interests in the Partnership. The Series B PIK Units have the right to share in distributions from the Partnership on a pro rata basis with holders of the Partnership's common units and will convert into common units on a one-for-one basis on the second anniversary of their initial issuance.

Business Strategies

Our principal business objective is to strategically grow the partnership in order to increase the quarterly cash distributions that we pay to our unitholders while ensuring the long-term stability of our business. We expect to achieve this objective by executing the following strategies:

Pursue Strategic and Accretive Acquisitions, Including Acquisitions from HPIP and Its Affiliates in Drop-Down Transactions. We plan to pursue accretive acquisitions of energy infrastructure assets, including in drop-down transactions from HPIP and its affiliates, 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 July 2012, we acquired from affiliates of Quantum Resources Management, LLC, an 87.4% undivided interest in the Chatom processing and fractionation plant and associated gathering infrastructure (the "Chatom system"). In October of 2013 we increased our ownership interest in the Chatom system to 92.2%. The Chatom system is located in Alabama, 15 miles from our Bazor Ridge system. In April 2013, we acquired the High Point System, which consists of approximately 700 miles of natural gas and liquids pipeline assets located in (i) southeast Louisiana, in the Plaquemines and St. Bernard parishes, and (ii) the shallow water and deep shelf Gulf of Mexico, including the Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound zones. Further, in December 2013, in a drop-down transaction, we closed the Blackwater Acquisition, and in January 2014, we closed the PVA Asset Acquisition.

Develop Strategic and Accretive New Asset Platforms. We plan to selectively pursue the development of new complementary midstream asset platforms in our current operating regions and in new midstream asset regions that provide attractive returns in regions where we currently do not have assets. As our customers move to produce in 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. For example, in May 2013 we announced that HPIP is developing well-stream gathering, treating, and processing infrastructure to gather and treat oil, natural gas, and produced water. HPIP has entered into a long-term, fee-based agreement to provide midstream services to a large independent producer in the oil window of the Eagle Ford Shale in Gonzales County, Texas. When fully operational, the gathering pipeline and treating/processing facility will have capacity for approximately 95,000 Bbl/d and 15 MMcf/d of natural gas. The initial phase of the Eagle Ford project is being developed by HPIP, which has granted us a right of first offer with respect to the agreement and the associated facilities. We believe HPIP intends to offer the assets to us, although they are not obligated to do so and we are not obligated to purchase such assets.

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 that 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 through aggressively marketing our services to additional customers in our areas of operation. We have available capacity on a majority of our systems; as a result, we can accommodate additional volumes at a minimal incremental cost.

Manage Exposure to Commodity Price Risk. We work to manage our commodity price exposure by targeting a contract portfolio that is weighted toward firm transportation, as well as fee-based and fixed-margin contracts while mitigating direct commodity price exposure by employing a prudent hedging strategy. For the years ended December 31, 2013 and 2012, $48.8 million and $23.7 million, or 63.6% and 48.6%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts, which have little or no direct commodity price exposure. Those contracts, together with our percent-of-proceeds contracts and hedging activities, generated relatively stable cash flows. As of December 31, 2013, we have hedged approximately 12% of our expected exposure to NGL prices and approximately 14% of our expected exposure to oil prices through the end of 2014. With respect to our exposure to natural gas prices, we are 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.

Pursue and 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 market environments.
Continue Our Commitment to Safe and 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 safely handle natural gas and NGLs for our customers, while striving to minimize the environmental impact of our operations. We have implemented a safety performance program, including an integrity management program, and planned maintenance programs to increase the safety, reliability and efficiency of our operations.
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 our larger competitors. Given the current size of our business, these opportunities may have a larger positive 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, which allows us to pursue the development of new systems that have the potential to positively impact our company but that would not be meaningful enough to gain the attention of our larger competitors.
Relationship with ArcLight. ArcLight controls the majority owner of our General Partner who has a proven track record of delivering superior returns across the energy industry value chain. ArcLight bases its investments on fundamental asset values and execution of defined growth strategies with a focus on cash flow generating assets and service companies with conservative capital structures. We believe our growth strategy may benefit from this relationship.
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 seven 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 who are underserved by our competitors. Drilling activity continues 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 economically add capacity to our systems; and
- the availability of multiple downstream interconnects that many of our systems have provides our customers with multiple market delivery options, thereby causing our systems to be more attractive compared to 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 Management and Operating Teams. Our executive management team has an average of 25 years' 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 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 participation in our Long-Term Incentive Plan.
Our Assets

We own and operate eleven gathering systems, two processing facilities, one fractionation facility, four terminal sites, three interstate pipelines and five intrastate pipelines. We also own a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant. Our assets are primarily located in Alabama, Georgia, Louisiana, Maryland, Mississippi, Tennessee and Texas. We organize our operations into three business segments: (i) Gathering

and Processing; (ii) Transmission; and (iii) Terminals.
The following table provides information regarding our segments and assets as of December 31, 2013, and for the years ended December 31, 2013 and 2012.

| | System Type | Contract Type (f) | Miles | Approximate Number of Connected Wells/ Receipt Points | Compression (Horsepower) | Approximate Design Capacity (MMcf/d) | Approximate Average Throughput (MMcf/d) Year Ended December 31, 2013 | 2012 |
|---|---|---|---|---|---|---|---|---|
| Gathering and Processing | | | | | | | | |
| Gloria | Gathering, Processing (e) | Fee (g), POP | 138 | 37 | 2,962 | 80 | 44.0 | 38.3 |
| Lafitte | Gathering | Fee (g) | 41 | 36 | — | 71 | 23.6 | 22.6 |
| Chatom (a) | Gathering, Processing Fractionating | Fee, POP | 24 | 10 | 3,456 | 25 | 7.6 | 4.1 |
| Bazor Ridge | Gathering, Processing | Fee, POP | 169 | 52 | 8,615 | 22 | 10.9 | 12.6 |
| Quivira | Gathering | Fee | 34 | 14 | — | 140 | 67.6 | 79.1 |
| Burns Point Plant (b) | Processing | POP | — | 3 | 11,000 | 200 | 97.6 | 98.2 |
| Offshore Texas | Gathering | Fee (g) | 56 | 23 | — | 100 | 4.7 | 15.2 |
| Other (c) | Gathering, Processing | Fee (g), POP | 196 | 445 | 5,621 | 153 | 21.2 | 21.1 |
| Total | | | 658 | 620 | 31,654 | 791 | 277.2 | 291.2 |
| Transmission | | | | | | | | |
| High Point | Intrastate | FT, IT | 663 | 75 | — | 1,120 | 279.4 | — |
| Bamagas | Intrastate | FT | 52 | 2 | — | 450 | 103.2 | 151.3 |
| AlaTenn | Interstate | FT, IT | 295 | 4 | 3,665 | 200 | 52.8 | 46.1 |
| Midla | Interstate | FT, IT | 370 | 9 | 3,600 | 198 | 150.3 | 130.4 |
| MLGT | Intrastate | FT, IT (g) | 54 | 7 | — | 170 | 42.7 | 44.5 |
| Other (d) | Intrastate | FT, IT | 82 | 6 | — | 336 | 22.1 | 26.2 |
| Total | | | 1,516 | 103 | 7,265 | 2,474 | 650.5 | 398.5 |

| Terminals (h) | | | Number of Tanks | Total Capacity | Contracted Capacity | Storage Utilization Year Ended December 31, 2013 | 2012 |
|---|---|---|---|---|---|---|---|
| Westwego | Tanks | Firm storage | 47 | 945,900 | 945,900 | 100.0% | — |
| Brunswick | Tanks | Firm storage | 5 | 221,000 | 221,000 | 100.0% | — |
| Salisbury | Tanks | Interruptible storage | 16 | 178,000 | 127,000 | 74.0% | — |
| Harvey (i) | Tanks | N/A | — | — | — | — | — |
| Total | | | 68 | 1,344,900 | 1,293,900 | 96.2% | |

(a) We have included approximate average throughput at 100% for our account of the 87.4% undivided interest in the Chatom system acquired effective July 1, 2012. In October 2013, we increased our ownership percentage in the Chatom system from 87.4% to 92.2%.

(b) The Burns Point Plant is connected to three pipelines, including the Quivira System, which are supported by over 40 wells and central delivery points. We have included approximate average throughput for the plant, in which we acquired a 50% undivided interest effective November 1, 2011.

(c) Includes our Fayette, Magnolia, Heidelberg and Madison systems, as well as the Alabama Processing system for the "Average Throughput" columns.

(d) Includes our TriGas and Chalmette systems.

(e) 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."

(f) 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.

(g) 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.

(h) Terminals amounts are for the period from April 15, 2013 to December 31, 2013.

(i) Upon receipt of required permits, the Harvey terminal will be improved and developed into a new bulk liquid storage terminal.

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;
- fractionating;
- transportation; and
- sales of natural gas, NGLs and condensate.

We own one processing plant on our Bazor Ridge system and one on our Chatom system (of which we own 92.2%). We previously owned two processing plants on our Alabama Processing system, which we sold in December 2013. 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 a plant that is connected to our Gloria system, the Toca plant. The Toca plant is owned and operated by Enterprise which also operates the Burns Point Plant. Our Bazor Ridge processing plant, the Chatom processing plant, the Burns Point Plant and the Toca plant are all cryogenic processing plants. These types of processing plants represent the current 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, for our producer and supplier customers and our own account. We have no keep-whole arrangements with our customers. On our Gloria, Lafitte, Offshore Texas, and other gathering and processing systems, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee. We subsequently transport that natural gas to delivery points on our systems, and then sell the natural gas at the undiscounted index price at which we purchased the natural gas, thereby earning a fixed margin on each transaction. We regard the segment gross margin we earn with respect to those purchases and sales as "fixed-margin" and as the economic equivalent fee for our transportation service. As such, we include these transactions in the category of fee-based contractual arrangements. In order to minimize the 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, 2013, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 23.6% and 76.4%, respectively, of our segment gross margin for the Gathering and Processing segment. For the year ended December 31, 2012, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 29.4% and 70.6%, respectively, of our segment gross margin for the Gathering and Processing 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. Due to low natural gas prices during much of 2013, our producers focused on re-completions rather than organic drilling and as a result, we connected one new supply source to our systems in our Gathering and Processing segment.

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

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 138 miles of pipeline, with diameters ranging from three to 16 inches, and four compressors with a combined size of 2,962 horsepower. The Gloria system has a design capacity of approximately 80 MMcf/d. Average throughput on the Gloria system for the year ended December 31, 2013, was 44.0 MMcf/d from approximately 37 connected wells and an interconnect with our Lafitte system. Average throughput on the Gloria system increased from approximately 38.3 MMcf/d for the year ended December 31, 2012, due to excess volumes from our Lafitte system. This increased throughput primarily resulted from increased volumes from the interconnect between the Lafitte system and Kinetica Energy Express, LLC, ("Kinetica"), an interstate pipeline owned by Kinetica Partners, LLC, as a result of line looping, interconnection and compression projects completed in 2012. 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 work-overs and recompletions of existing wells. An average of two wells per year were connected to the Gloria system over the last three years, with no wells connected during the year ended December 31, 2013. Producers generally bear the cost of connecting their wells to our Gloria system.

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 POP processing contract with Enterprise in July 2011 that allows us to process raw natural gas through the Toca plant, whether for our customers and our own account. This contract has an initial term of seven years and covers volumes from both our Gloria and Lafitte systems. The 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 directly through the Sonat pipeline as well as through various interconnects downstream of the Toca plant. Sonat is the primary pipeline into which Toca volumes are currently delivered. Sonat sold its Gulf of Mexico gathering facilities located upstream of the Toca Plant to High Point Gas Transmission, LLC, a subsidiary of the Partnership.

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/Kinetica interconnect, provide us with the flexibility to decide whether to process natural gas through the Toca plant and capture processing margins for our own account or deliver the natural gas into the interstate pipeline market at the inlet to the Toca plant. We make this decision based on the relative prices of natural gas and NGLs on a monthly basis. We refer to the flexibility built into these contracts as our elective processing arrangements. Due to generally strong processing margins, we currently process at the Toca Plant the majority of the natural gas purchased on the Gloria system that is available for processing. In addition, we process the natural gas purchased via the Lafitte/Kinetica interconnect that is in excess of the needs of Phillips66. 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 41 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 Phillips66. Average throughput on the Lafitte system for the years ended December 31, 2013 and 2012, was 23.6 MMcf/d and 22.6 MMcf/d, respectively, from approximately 36 connected wells and an interconnect with Kinetica 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 Phillips66 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 one well connected during the year ended December 31, 2013. Producers generally bear the cost of connecting their wells to our Lafitte system.

In December 2010, we completed an interconnect between our Lafitte pipeline and the Kinetica interstate system, which at the time was operated by Tennessee Gas Pipeline Company LLC ("TGP"), a subsidiary of Kinder Morgan. This interconnect provides a redundant source of natural gas supply for the Alliance Refinery to the extent that the Lafitte native production is insufficient to supply the needs of the refinery. This 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.

Chatom System

The Chatom system consists of a 25 MMcf/d cryogenic processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 24-mile gas gathering system. The system is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi. The Chatom system gathers natural gas from onshore oil and natural gas wells in Alabama and Mississippi.

We have POP arrangements with each of the customers operating these wells. After processing, the residue natural gas is sold and delivered to Clarke Mobile, a local distribution company in Alabama, at a Florida Gas Transmission Zone 3 index-based price. The NGLs are fractionated at the Chatom system then sold at the tailgate of the plant to various counterparties at a Mt. Belvieu index-based price. Condensate in the inlet natural gas stream is separated at the plant and sold at the tailgate to Shell Trading (US) Company at a Louisiana Light Sweet index-based price. Sulfur is recovered from the inlet natural gas stream and sold to a local sulfur consumer at a Tampa index-based price. Additionally, the Chatom system fractionates NGLs from third-party suppliers under fee-based fractionation agreements. The contract consists of a fee-based component as well as an arrangement to purchase and resell the fractionated NGLs at indexed pricing.

Average natural gas throughput on the Chatom system for the year ended December 31, 2013, and 2012, was approximately 7.6 MMcf/d and 4.1 MMcf/d, respectively, from 10 wells. Average NGL and condensate sales for the years ended December 31, 2013 and 2012, were approximately 45.0 Mgal/d and 20.0 Mgal/d, respectively.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 169 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 as well as 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 either 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, or transport them to our Chatom system for fractionation and sale. The NGLs are sold on a Mt. Belvieu index-based price. In 2010, we built an 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% up to the plant capacity. In conjunction with the construction of the Winchester lateral, we negotiated a five-year acreage dedication from Venture. Average throughput on the Bazor Ridge system for the years ended December 31, 2013 and 2012, was approximately 10.9 MMcf/d and 12.6 MMcf/d, respectively.

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 two wells per year was connected to our Bazor Ridge gathering system over the last three years, with no wells connected during the year ended December 31, 2013. Despite no wells being connected, the generally stable production and relatively modest decline rates from this formation allow us to maintain steady throughput on our Bazor Ridge system.

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 the plant 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, Sonat or the Gulf South Pipeline system, an interstate pipeline owned by Boardwalk Pipeline Partners, LP.

The Quivira system is partially subscribed under a firm transportation arrangement through 2014, although a substantial proportion of the revenue is derived from volumetric and fee-based charges. Average throughput on the Quivira system for the year ended December 31, 2012, was approximately 79.1 MMcf/d from 14 connected wells. Average throughput decreased to approximately

67.6 MMcf/d for the year ended December 31, 2013, as a result of production shut-ins and changes to production profiles associated with an interconnect to a gathering system owned and operated by a certain producer.

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 one well per year was connected to the Quivira system over the last three years. No wells were connected during the year ended December 31, 2013. Producers generally bear the cost of connecting their wells to our Quivira system.

Burns Point Plant

We hold a 50% undivided, non-operating interest in the Burns Point Plant located in St. Mary Parish, Louisiana, which 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 supplied up to approximately 80% of the inlet volume to the plant during 2013. The residue gas is transported via pipeline to Gulf South, Sonat and TGP, 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.

Average throughput on the Burns Point Plant for the years ended December 31, 2013 and 2012, was approximately 97.6 MMcf/d and 98.2 MMcf/d, respectively.

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 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 that remove water and other impurities from the gathered natural gas before delivering it to market. 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, which is currently shut-in, and connects onshore to the Dow Pipeline system, an intrastate pipeline owned by Dow Chemical Company.

Average throughput on the Offshore Texas system for the years ended December 31, 2013 and 2012, was 4.7 MMcf/d and 15.2 MMcf/d, respectively, from approximately 22 connected wells.

All of the wells in this area are natural gas wells producing from the Gulf of Mexico shelf offshore Texas. One well per year was connected to the Offshore Texas system over the last three years. No wells were connected during the year ended December 31, 2013. Producers generally bear the cost of connecting their wells to our Texas Offshore system.

Other Gathering and Processing Assets

Magnolia System. The Magnolia gathering system, currently presented as held for sale, is a Section 311 intrastate pipeline that gathers coal-bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transcontinental Gas Pipe Line Co, ("Transco") pipeline system, an interstate pipeline owned by The Williams Companies, Inc. The Magnolia system consists of approximately 116 miles of pipeline with small-diameter gathering lines and trunk lines ranging from six to 24 inches in diameter and one compressor station with 3,328 horsepower. The Magnolia system has a design capacity of 120 MMcf/d.

Average throughput on the Magnolia system for the years ended December 31, 2013 and 2012, was 16.0 MMcf/d and 15.5 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, currently presented as held for sale, and Heidelberg gathering systems, located in Fayette County, Alabama, and Jasper County, Mississippi, respectively. The design capacities for these systems are 5 MMcf/d and approximately 18 MMcf/d, respectively. Average throughput for these systems was 0.5 MMcf/d and 3.0 MMcf/d, respectively, during the year ended December 31, 2013, and 0.5 MMcf/d and 4.0 MMcf/d, respectively, during the year ended December 31, 2012.

Customers

With respect to our Gathering and Processing segment, substantially all of the natural gas produced on our Lafitte system is sold to ConocoPhillips for use at the 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 four years. For the year ended December 31, 2013, our Gathering and Processing segment derived 43% and 19% of its revenue from ConocoPhillips and Shell, respectively. For the year ended December 31, 2012, our Gathering and Processing segment derived 40%, 12% and 11% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Shell, 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 ("LDCs"), electric utilities, 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 often 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, with FERC approval, we can have rates or certain other terms that are different from those generally provided for in the FERC tariff. For our High Point, 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, 2013:

| | Tariff Revenue Composition | | | | |
|---|---|---|---|---|---|
| | Firm Transportation Contracts | | | | |
| Asset | 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) |
| High Point | — | — | 100% | — | <1 |
| Bamagas | 100% | — | — | 44% | 6 |
| AlaTenn | 86% | 7% | 7% | 24% | <1 |
| Midla | 70% | 9% | 21% | 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) Includes fixed margin arrangements.

High Point System

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The High Point system consists of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. The High Point system gathers natural gas from both onshore and offshore producing regions around southeast Louisiana. The onshore footprint is Plaquemines and St. Bernard Parish, Louisiana. The offshore footprint consists of the following federal Gulf of Mexico zones: Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound. Natural gas is collected at more than 75 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on oil and liquids-rich reservoirs. The High Point System is comprised of FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. The High Point System delivers the natural gas to the Toca Gas Processing Plant, operated by Enterprise, where the products are processed and the residue gas is sent to an unaffiliated interstate system owned by Kinder Morgan. Average throughput on the High Point system for the year ended December 31, 2013, was approximately 279.4 MMcf/d.

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, 2013 and 2012, was approximately 103.2 MMcf/d and 151.3 MMcf/d, respectively. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements. Calpine 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 over 25 active delivery points, including the Tetco Pipeline system, an interstate pipeline owned by Spectra Energy Transmission, LLC, 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, 2013 and 2012, was approximately 52.8 MMcf/d and 46.1 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. The Midla system is connected to nine receipt and over 40 active delivery points.

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 21.8 MMBtu/d and 33.4 MMBtu/d of natural gas for the years ended December 31, 2013 and 2012, respectively.

The mainline has a design capacity of approximately 198 MMcf/d and consists of approximately 170 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, 2013 and 2012, was approximately 150.3 MMcf/d and 130.4 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.

On November 29, 2013, we announced an open season to offer current and prospective shippers the opportunity to subscribe to firm capacity on one or more versions of a proposed reconstruction of the mainline pipeline in Louisiana and Mississippi. The open season was to gauge customer interest in replacement of the existing Midla pipeline, which runs from Monroe to Baton Rouge, Louisiana, either in whole or in part. The open season did not yield long-term commitments sufficient to justify reconstruction of all or a portion of the mainline, therefore we may commence with the regulatory process necessary to abandon certain segments beginning in the late spring or early summer of 2014.

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 several 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, 2013 and 2012, was approximately 42.7 MMcf/d and 44.5 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 8.8 MMcf/d and 13.4 MMcf/d, respectively, for the year ended December 31, 2013, and 9.8 MMcf/d and 16.5 MMcf/d, respectively, for the year ended December 31, 2012. Finally, we also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

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 four years and less than one year, respectively. ExxonMobil and Enbridge Marketing (US) L.P. are the two largest purchasers of natural gas and transmission capacity in our Transmission segment and accounted for approximately 39% and 16%, respectively, of our segment revenue for the year ended December 31, 2013; ExxonMobil, Enbridge Marketing (US) L.P., and Calpine Corporation accounted for approximately 50%, 22% and 10%, respectively, of our segment revenue for the year ended December 31, 2012.

Terminals Segment

General

On December 17, 2013, the Partnership acquired Blackwater. Blackwater operates 1.3 million barrels of storage capacity across four marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners, and chemical manufacturers, to store a range of products, including crude oil, bunker fuel, distillates, chemicals and agricultural products.

Westwego Terminal Operations

The Westwego Terminal site consists of 47 above-ground storage tanks for a combined capacity of 945,900 barrels. Currently, we plan to expand by constructing two additional 50,000 barrel above-ground storage tanks. Our operations support many different commercial customers, including commodity brokers, refiners and chemical manufacturers. Our location within the Port of New Orleans, the warehousing and international distribution attributes this location provides, along with our broad customer base, contributes to the potential diversity of the products customers may want stored in our terminal. The products will, however, generally fall into two broad categories: chemical and agricultural.

Our income from the Westwego Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products; and other services requested by our customers, such as blending services. The terms of our storage capacity contracts range from month-to-month to multiple years, with renewal options.

At the Westwego Terminal, we generally receive our customers' liquid product by river vessel at our Mississippi River dock and by railcar. The product is transferred from the river vessels and railcars to the specified storage tank via the terminal’s internal pipeline system. The customer’s product is removed from storage at our terminal by truck, railcar and/or water vessel. The length of time that the customer’s product is held in storage without transfer varies depending upon the customer’s needs.

Brunswick Terminal Operations

The Brunswick Terminal site consists of one 60,000-barrel above-ground storage tank, two 80,000-barrel above-ground storage tanks and two 500-barrel above-ground storage tanks for a combined capacity of 221,000 barrels. The Brunswick Terminal is currently leasing land from the Georgia Ports Authority that is scheduled to terminate on September 4, 2016.

This terminal is ideally suited to serve petroleum, chemical and agricultural customers who need deep-water access and distribution in the southeastern sector of the United States of America. Income from the Brunswick Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products; and other services requested by our customers, such as blending services. The terms of our storage capacity contracts will range from month-to-month to multiple years, with renewal options.

At the Brunswick Terminal we offer product transfer via river vessel, railcar and bulk-liquid carrying truck. At the Brunswick Terminal, the customer’s liquid product is received by barge or ship at the dock. The product is transferred from barges or ships to the storage tank via the terminal’s internal pipeline system. The customer’s product is removed from storage at our terminal by truck, railcar and/or barge or ship. The length of time that the customer’s product is to be held in storage without transfer will vary depending on the customer’s needs.

Harvey Terminal Operations

The Harvey Terminal consists of approximately 56 acres of property and facilities located in Harvey, Louisiana. The land is adjacent to the Mississippi River, and the assets include dormant storage tanks, unoccupied buildings, a barge dock and other improvements. Activity is underway to clear the site of debris. Upon receipt of required permits, we will improve other assets and build new assets to develop the site into a new bulk-liquid storage terminal.

Salisbury Terminal Operations

The Salisbury Terminal site, which is currently presented as held-for-sale, consists of 14 above-ground storage tanks for a combined capacity of approximately 178,000 barrels. This terminal is ideally suited to serve petroleum distributors and agricultural customers who need distribution in the Delmarva Peninsula area of Maryland. Income from the Salisbury Terminal is derived from throughput charges for receipt and delivery of our customers' products, as well as other services. The terms of our storage capacity contracts will range from month-to-month, to multiple years, with renewal options.

At the Salisbury Terminal, we offer product transfer via river barges and by bulk-liquid carrying truck. At the Salisbury Terminal the customer’s liquid product is mostly received by barge at the dock. The product is transferred from barges to the storage tank via the terminal’s internal pipeline system. The customer’s product is removed from storage at our terminal by truck. The length of time that the customer’s product is to be held in storage without transfer will vary depending on the customer’s needs.

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, Gulf South and ANR.

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.

In our Terminals segment, we compete with a number of existing storage facilities within the New Orleans to Baton Rouge, Louisiana refining and manufacturing corridor, the southeast USA, Florida and Georgia area and the Delmarva, Maryland Peninsula area. Our major competitors for this segment are Kinder Morgan, International Matex Tank Terminals and the Westway Group.

Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Other Segment Information

For additional information on our segments, including revenues from customers, profit or loss and total assets, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 15. “Exhibits and Financial Statement Schedules.”

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 by 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. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The PHMSA 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 these 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. 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 U.S. 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 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; 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.

Regulation of our terminals require us to maintain and currently hold approvals and permits from federal, state and local regulatory agencies for air quality and water discharge, as well as standard local occupational licenses.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of FERC pursuant to the 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 four rehearing orders which generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct.

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 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, other orders issued by the FERC upholding the FERC's income tax allowance policy and the issue of the inclusion of an income tax allowance have been the subject of extensive litigation before the FERC. The FERC's most recent order upholding the policy was issued in September 2012. Several parties have appealed this FERC order. 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 the income tax allowance 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, in 2010 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's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional 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 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 the numerous requests for rehearing of 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 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 2012, 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"). In October 2011, the BOEMRE was reorganized into and replaced by two separate agencies, the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"). The BOEM manages the exploration and development of the nation's offshore resources. BOEM seeks to appropriately balance economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.

BSEE works to promote safety, protect the environment, and conserve resources offshore through vigorous regulatory oversight and enforcement.

Sales of Natural Gas and NGLs

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, terminals 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 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 soil and 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 and Chatom systems, 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 H2S. 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 SO2, per year.

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 issued final guidance to reinvigorate NEPA reviews which, while intended to streamline the process, 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. In June 2013, President Obama issued a climate action plan to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations. This climate Action Plan, in addition to recent state and federal regulation initiatives and threatened litigation by northeastern states to force EPA to craft standards for methane emissions from oil and gas operations, signal a new focus on methane emissions that has the potential to pose substantial regulatory risks to our operations. 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. The D. C. Circuit upheld the Tailoring Rule, but the Supreme Court granted cert and will hear the case in February 2014.

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 and Chatom systems are currently required to and have reported under this rule in 2012 and 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. We timely filed emissions reports for our Bazor Ridge and Chatom systems.

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. 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, 2013, our general partner employed approximately 170 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.

### General

We make certain filings with the SEC (the “SEC”), including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports. All of these filings are available as soon as reasonably practicable after the electronic filing with the SEC free of charge on our website, www.americanmidstream.com. The filings are also available at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549 or by calling the SEC at 1-800-SEC-0330. Additionally, the filings are available on the internet at www.sec.gov. The information contained on our website is not part of, nor is it incorporated by reference into, this Annual Report on Form 10-K.

## 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 this Annual Report 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

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

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

We may not have sufficient cash from operations following the preferred distribution on our Series A convertible preferred units, 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 Series B PIK 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 common unit or distributions associated with Series B PIK units. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our Series A convertible preferred units are entitled, the establishment of cash reserves, and payment of our fees and expenses. 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;
- storage capacity utilization associated with our terminals segment;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating, maintenance and general and administrative costs;
- 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 and our operating flexibility; and
- acts of God.

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, and the resulting costs of integrations, 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, including volumes from significant customers, 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.

Global economic conditions may have adverse impacts on our business and financial condition.

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, government spending sequestration, strength of U.S. currency versus other international currencies, consumer confidence and debt levels, retail trends, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs and higher tax rates may adversely affect demand for natural gas and NGLs. Also, any tightening of the capital markets could adversely impact our ability to execute our long-term organic growth projects and meet our obligations to our producer customers and limit our ability to raise capital and, therefore, have an adverse impact on our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

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 2013 ranged from a high of $4.46 per MMBtu to a low of $3.11 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 2013 ranged from a high of $110.53 per Bbl to a low of $86.68 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, 2013 and 2012, percent-of-proceeds arrangements accounted for approximately 36.4% and 51.3%, respectively, of our gross margin, or 76.4% and 70.6%, respectively, of the segment gross margin in our Gathering and Processing segment.

Our hedging activities may not be effective in reducing our direct exposure to commodity price risk 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 2014. 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.

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.

We are a relatively small enterprise, and our management has limited history and experience with our specific assets. 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 may 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 specific business and assets. 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. 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.

We currently have limited accounting personnel, and while we continue to evaluate 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 the effectiveness of our internal controls over financial reporting.

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 of these customers could adversely affect our ability to make distributions.

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. For information regarding our concentration of customers and associated credit risk by segment, please refer to Part I, Item 1. Business in this Annual Report. Although we have gathering, processing and transmission contracts with significant 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 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.

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. For the year ended December 31, 2013, our Gathering and Processing segment derived 43% and 19% of its revenue from ConocoPhillips and Shell, respectively. For the year ended December 31, 2012, our Gathering and Processing segment derived 40%, 12% and 11% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Shell, respectively. Additionally, ExxonMobil and Enbridge Marketing (US) L.P. are the two largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 39% and 16%, respectively, of our segment revenue for the year ended December 31, 2013 and ExxonMobil, Enbridge Marketing (US) L.P., and Calpine Corporation approximately 50%, 22% and 10%, respectively, of our segment revenue for the year ended December 31, 2012.

Some of our customers and purchasers 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 or purchasers could have a material adverse effect on our revenue, gross margin and cash flows and our ability to make cash distributions to our unitholders.

Due to our lack of asset diversification, adverse developments in our gathering, processing, transportation, transmission and storage operations could reduce our cash flows available for distribution to our unitholders.
We rely on the revenues generated from our gathering, processing, transportation, transmission and storage operations. An adverse development in one of these areas would have a significantly greater impact on our operations and cash flows available for distribution to our unitholders than if we maintained more diverse assets.
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 Kinetica 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 gathering, processing, transportation and terminal 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. We provide above-ground storage services at our marine terminals that support various commercial customers. 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.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers’ natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act (“SDWA”), fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 20, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands; a revised rule was released for public comment on May 25, 2013. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed by 2014. The adoption and implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

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, transportation or terminaling 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.

Significant portions of the pipeline systems that we purchased had been in service for many decades prior to our purchase. Consequently, our executive management team has a limited history of operating such 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 safety regulation, including pipeline integrity management program testing and related repairs.

Pursuant to the PSIA, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the 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 $1.4 million during 2014 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.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In addition, PHMSA has published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements or to include additional pipelines in “high consequence areas”. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services.

Recent spills 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 our offshore natural gas gathering activities.

In April 2010, a deep-water 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 deep-water operations in the Gulf of Mexico. 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 offshore operations, and our business, financial condition and results of operations. We cannot predict with any certainty what form any additional regulation or limitations will take.

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 may 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.
If we are unable to timely and successfully integrate our acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transaction.
Our future growth may depend in part on our ability to integrate our acquisitions. We cannot guarantee that we will successfully integrate any acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash flows available for distribution to our unitholders.

The integration of acquisitions with our existing business involves numerous risks, including:

- operating a significantly larger combined organization and integrating additional midstream operations into our existing operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and

- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities including those under the same stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are applicable to our existing plants, pipelines and facilities. If so, our operation of these new assets could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with such requirements. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we may 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, or the construction of new 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 have agreed to construct gas gathering pipelines to service existing and future PVA properties (excluding the PVA Assets), which involves potential risks.

In connection with the PVA Asset Acquisition, we agreed, at our cost and expense, to design, acquire right-of-way for, obtain all permits from governmental authorities for, procure materials for, construct, operate, and maintain additional gathering pipelines for connection to certain current and future PVA properties (excluding the PVA Assets). There are risks involved with such obligations, including:

- general construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the inability to obtain required permits for the pipelines;
- the inability to obtain rights-of-way for the gathering pipelines, which may result in pipelines being re-routed, which itself could result in cost overruns and delays;
- the risk associated with PVA's exploration and production activities and the associated potential failure of the gathering pipelines to generate attractive cash flows given our obligation to construct and operate them; and
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title issues or environmental or regulatory compliance matters or liabilities or accidents associated with the construction or operation of the pipelines.

While we cannot guarantee with any certainty the future costs associated with such construction, operation, and maintenance, we currently expect that the aggregate capital expenditures over the next five years associated with this expansion construction will be $60-70 million, including approximately $30 million to be incurred in 2014. Initially, we expect to fund these costs with borrowings under our credit facility. If we are unable to finance the expansion costs with existing liquidity, we could be required to seek alternative sources of liquidity, which could be costly or may not be available. In the event expansion and extension of the PVA properties (excluding the PVA Assets) is significantly more expensive than we expect or we are unable to obtain financing for such construction, it could have a material adverse effect on our financial condition, including our results of operations and cash flows.

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.

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.

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 FERC, under the 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, 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 EPAct 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. 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 certain profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the EPAct 2005 amended the NGA and the 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.

The application of certain FERC policy statements could affect the rate of return on our equity that we are allowed to recover through rates and the amount of any allowance 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, FERC's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional 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. Such additional scrutiny could result in increased expenses to us and a resulting materially adverse change in our finances.
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 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.
On March 11, 2013, the EPA issued a Clean Air Act Compliance Order related to an inspection of the Chatom processing plant on May 15, 2012. The order was issued to Quantum Resources Management, LLC, the owner at the time of the inspection. The EPA has requested information regarding releases identified during the inspection, including a description of the equipment and repairs that were performed. We have timely responded to this request. At this time, we cannot determine whether the EPA may pursue further enforcement related to these releases and cannot predict the amount of any potential fines or penalties. Further enforcement could result in increased expenses to us and a resulting materially adverse change in our finances.
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. Please read "Business - Environmental Matters - Air Emissions" for more information about these matters.
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. We may not be able to recover all or any of these costs from insurance. 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. Please read “Business - Environmental Matters” for more information.

We may be unable to obtain or renew permits necessary for our operations or the operations we may acquire in future acquisitions.

Our facilities operate under a number of required federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approvals, limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval, limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed material permit, license or approval, or to revoke or substantially modify an existing permit, license or approval, could have a material adverse effect on our financial condition, including our results of operations and cash flows.

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” for more information.

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 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. Final rules are expected in 2014.

The EPA could develop new rules and current rules may be modified.

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. 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 annually. We filed emission reports for our Bazor Ridge and Chatom systems in March 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.

On August 16, 2012, the EPA published final rules that establish new air emission controls for natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards ("NSPS") 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 rules establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants. Under these rules we are required to modify some of our operations, though we do not expect these modifications to have a material effect on our operations. Following the publication of the final rule, the EPA received petitions for reconsideration of certain aspects of the standards. On April 12, 2013, the EPA published proposed updates to the NSPS Section OOOO storage tank requirements. On September 23, 2013, the EPA published final revisions to the NSPS Section OOOO storage tank requirements, including a phase-in of installation of VOC controls and alternate limits for tanks where emissions have declined.

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.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. 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 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. While we believe that this rule does not apply to any of our pipelines, 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 and the 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.

We hedge a portion of our commodity risk and our interest rate risk. The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including businesses like ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Act, was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act, the CFTC adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC had filed a notice of appeal with respect to this ruling but on October 29, 2013 voted to voluntarily dismiss this appeal. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. Comments on these new rules were due in early January 2014, and, as these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. Under the rules adopted by the CFTC, we believe our hedging transactions will qualify for the non-financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations

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, or we may not be able to renew our contract leases on commercially reasonable terms or at all. 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.

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.

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. Our management team devotes a portion of its efforts to projects owned and operated by our general partner, which means they are not devoted 100% of their time to the Partnership. 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 hiring for such persons in the midstream natural gas industry is competitive. 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. 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 adversely affect 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 or downtime, 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 operational departments, 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.

Our assets and operations can be affected by weather, weather related conditions and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on some of our assets on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Terrorist attacks, the threat of terrorist attacks, and sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001 and the threat of future terrorist attacks on our industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East and North Africa or other sustained military conflicts may affect our operations in unpredictable ways, including disruptions of crude oil supplies or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Risks Related to Our Units, Corporate Structure and Ownership

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity investees. As a result, our ability to make required payments on our notes or make distributions depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations. If our subsidiaries are prevented from distributing funds to us, we may be unable to pay all the principal and interest on the notes when due.

The amount of cash we have available for distribution to holders of our common, Series A convertible preferred and Series B PIK 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.

As our common units are 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.

High Point Infrastructure Partners, LLC, an affiliate of ArcLight Capital Partners, and AIM Midstream Holdings directly own our general partner, which has sole responsibility for conducting our business and managing our operations. High Point Infrastructure Partners elects all of the members of the board of our general partner. High Point Infrastructure Partners, 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.

High Point Infrastructure Partners and AIM Midstream Holdings own our general partner. High Point Infrastructure Partners has the power to appoint all of the officers and directors of our general partner, some of whom are also officers of High Point Infrastructure Partners. 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 owners, High Point Infrastructure Partners and AIM Midstream Holdings. Conflicts of interest may arise between High Point Infrastructure Partners and 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 High Point Infrastructure Partners and 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 High Point Infrastructure Partners or 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 such 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 Series A Convertible Preferred 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 Series A Convertible Preferred Units or Series B PIK Units , to make incentive distributions or to accelerate the expiration of a 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 Series A Convertible Preferred Units and Series B PIK 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.

High Point Infrastructure Partners and AIM Midstream Holdings are not limited in their ability to compete with us and are 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.

High Point Infrastructure Partners and AIM Midstream Holdings are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, High Point Infrastructure Partners and 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 High Point Infrastructure Partners and AIM Midstream Holdings may offer us the opportunity to buy additional assets from them, they are under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

The New York Stock Exchange ("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” for more information.

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 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.

Common 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 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 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 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 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 it has received incentive distributions exceeding the target distribution described in our partnership agreement 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.

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 High Point Infrastructure Partners. 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.
Our unitholders are unable to remove our general partner without its consent because our general partner and its affiliates own 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. As of March 7, 2014, High Point Infrastructure Partners owns 5,353,970 Series A convertible preferred and 1,168,225 Series B PIK Units which, if converted one-for-one, would represent 36.5% of our then-outstanding common units. AIM Midstream Holdings owns 8.9% of our outstanding limited partner 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 High Point Infrastructure Partners to transfer all or a portion of their 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 of the Series A Convertible Preferred 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.

High Point Infrastructure Partners and 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.

High Point Infrastructure Partners holds 5,353,970 Series A Convertible Preferred Units. The Series A Convertible Preferred Units are convertible into common units at the election of High Point Infrastructure partners at any time after January 1, 2014. In addition, High Point Infrastructure Partners and AIM Midstream Holdings control our general partner, which holds 1,168,225 Series B PIK Units, which will convert into common units on a one-for-one basis on January 31, 2016. AIM Midstream Holdings currently holds an aggregate of 988,495 common units. 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. As of March 7, 2014, High Point Infrastructure Partners owns 5,353,970 Series A convertible preferred and 1,168,225 Series B PIK Units which, if converted one-for-one, would represent 36.5% of our then-outstanding common units. AIM Midstream Holdings owns approximately 5.5% of our outstanding common units assuming conversion of the Series A convertible preferred and Series B PIK 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, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or the IRS were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity-level taxation for state tax purposes, 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 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. Although we do not believe based upon our current operations that we will be treated as a corporation, the IRS could disagree with the positions we take or 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%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a 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.
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. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of the U.S. Congress have considered, and the President’s Administration has proposed, substantive changes to the existing U.S. federal income tax laws that would affect the

tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such change could negatively impact the value of an investment in our common units.

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. For example, we are required to pay the State of Texas a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Imposition of such a tax on us by any other state will reduce the cash available for distribution to a unitholder. The 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 levels will be adjusted to reflect the impact of that law on us.

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 tax liability resulting from that income.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder's share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder's units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder's tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to the our assets.

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 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 materially and adversely impact 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 such 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 a unitholder sells our common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions to a unitholder in excess of the total net taxable income allocated to the unitholder decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions will, in effect, become taxable income to the unitholder if the unitholder sell the common units at a price greater than the unitholder's tax basis in those common units, even if the price received by the unitholder is less than the original cost. Furthermore, a substantial portion of the amount realized on any sale of a unitholder's 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 the unitholder sells common units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

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 individual retirement accounts (known as IRAs), or other retirement plans 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, which may be taxable to them. Distributions to non-U.S. persons will be reduced by federal withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal 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 our unitholders. 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 the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholders' tax returns.
We 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 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. Although 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, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge our proration 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.
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 such 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. 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 modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.
We have adopted certain valuation methodologies 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, 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 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 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 as a 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. Our technical termination, among other things, would 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 Schedule K-1's if relief from the IRS was not granted, as described below) for one calendar year. Our termination could also 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 calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Under current law, a technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination, 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 announced a publicly traded partnership technical termination relief procedure whereby, if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years resulting from the technical termination.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not reside as a result of investing in our units.

In addition to federal income taxes, unitholders may be subject to other taxes, including foreign, 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, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all U.S. federal, foreign, 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.

Some of the states in which we do business or own assets may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state, local 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 or impact our utilization of net operating losses 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 1400 16$^{th}$ Street, Suite 310, Denver, CO 80202 and our telephone number is 720-457-6060.

Item 3. Legal Proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental in our business. While the ultimate impact of any proceedings cannot be predicted with certainly, our management believes that the resolution of any of our pending proceeds will not have a material adverse effect on our financial condition or results of operations.

Although we are not currently party to any pending litigation or governmental proceedings, during the last fiscal year we were party to litigation, as described herein, that has since been resolved. On September 5, 2013, following the announcement of the

Equity Restructuring, AIM Midstream Holdings filed an action in Delaware Chancery Court against HPIP, our general partner and us. Among other claims, the action asserted a claim of tortuous interference with contract against the Partnership, and sought either rescission of the Equity Restructuring or, in the alternative, monetary damages. As a result of the action filed by AIM Midstream Holdings, the warrants that were issued by the Partnership, in conjunction with the Equity Restructuring, to the general partner for subsequent conveyance to AIM Midstream Holdings were cancelled effective August 29, 2013. In addition to the action filed by AIM Midstream Holdings, the escrowed funds of $12.5 million were not released to the Partnership. Accordingly, HPIP contributed $12.5 million in cash to the Partnership which was used to satisfy obligations under our credit agreement and was accounted for as a contribution from our general partner.

On February 5, 2014, HPIP, the Partnership and our general partner entered into a settlement (the “Settlement”) with AIM Midstream Holdings regarding the action filed in Delaware Chancery Court by AIM Midstream Holdings. Under the Settlement, among other things:

- HPIP and AIM Midstream Holdings amended the limited liability company agreement of our General Partner (the “LLC Amendment”) to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP’s sharing percentage is now 95% and AIM Midstream Holdings’s Sharing Percentage is 5%;

- HPIP transferred all of the 85.02% of the Partnership’s outstanding new IDRs held by HPIP to the General Partner such that the General Partner owns 100% of the outstanding new IDRs; and

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

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 during 2013 and 2012, together with distributions paid subsequent to each quarter for that quarter through December 31, 2013:

| Period Ended | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
|---|---|---|---|---|
| 2013 | | | | |
| High Price | $28.80 | $22.60 | $23.00 | $18.89 |
| Low Price | $17.51 | $18.71 | $15.65 | $13.74 |
| Distribution per common unit | $0.4525 | $0.4525 | $0.4325 | $0.4325 |
| 2012 | | | | |
| High Price | $19.44 | $21.75 | $22.77 | $22.80 |
| Low Price | $13.64 | $18.65 | $18.90 | $18.89 |
| Distribution per common unit | $0.4325 | $0.4325 | $0.4325 | $0.4325 |

As of March 7, 2014, there were 38 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 approximately 5,353,970 Series A convertible preferred units, 1,168,225 Series B PIK Units and 235,129 general partner units, for which there is no established trading market. The holders of Series B PIK units share in distributions from the Partnership on a pro rata basis with the holders of the common units. Our general partner and its affiliates receive quarterly distributions on the general partner units only after the requisite distributions have been paid on the common, Series A preferred units and Series B PIK units. In January 2014, we issued an additional 3,400,000 common units in a public offering.

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. We pay the cash dividend in one payment to those unitholders of record on the applicable record date, as determined by the general partner.

The following table sets forth the number of units at December 31, 2013 and 2012 (in thousands):

| | December 31, 2013 | 2012 |
|---|---|---|
| Series A convertible preferred units | 5,279 | — |
| Limited partner common units | 7,414 | 4,639 |
| Limited partner subordinated units | — | 4,526 |
| General partner units | 185 | 185 |

Our general partner's initial 2.0% interest in distributions has been reduced due to the issuance of additional units and the General Partner has not contributed a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.

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 5th 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. On July 11, 2012, the board of directors of our general partner adopted a second amended and restated long-term incentive plan that effectively increased available awards by 871,750 units. At December 31, 2013, 2012 and 2011, there were 855,089, 920,193 and 54,827 units, respectively, available for future grant under the LTIP.

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 2013, 2012, and 2011 begin on F-1 to this Annual Report.

We acquired Blackwater, effective December 17, 2013, which is accounted for as a transaction under common control therefore these consolidated financial statements include Blackwater presented from the period April 15, 2013 through December 31, 2013. 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, 2013 | Year Ended December 31, 2012 | Year Ended December 31, 2011 | Year Ended December 31, 2010 | Period from August 20, 2009 (Inception Date) to December 31, 2009 | 10 Months Ended October 31, 2009 |
| | (in thousands, except per unit and operating data) | | | | | |
| Statement of Operations Data: | | | | | | |
| Revenue | $292,626 | $194,843 | $233,169 | $195,087 | $29,892 | $ 129,614 |
| Realized loss in early termination of commodity derivatives | — | — | (2,998) | — | — | — |
| Gain (loss) on commodity derivatives | 28 | 3,400 | (2,452) | (308) | — | — |
| Total revenue | 292,654 | 198,243 | 227,719 | 194,779 | 29,892 | 129,614 |
| Operating expenses: | | | | | | |
| Purchases of natural gas, NGLs and condensate | 214,149 | 145,172 | 187,398 | 157,682 | 23,864 | 100,613 |
| Direct operating expenses | 29,553 | 16,798 | 11,419 | 10,944 | 1,477 | 9,328 |
| Selling, general and administrative expenses | 21,402 | 14,309 | 11,082 | 7,120 | 1,196 | 8,577 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Advisory services agreement termination fee | — | — | 2,500 | — | — | — |
| Transaction expenses | — | — | — | 303 | 6,404 | — |
| Equity compensation expense (a) | 2,094 | 1,783 | 3,357 | 1,734 | 150 | — |
| Depreciation expense | 29,999 | 21,284 | 20,449 | 19,904 | 2,962 | 12,540 |
| Total operating expenses | 297,197 | 199,346 | 236,205 | 197,687 | 36,053 | 131,058 |
| Gain on acquisition of assets | — | — | 565 | — | — | — |

| | | | | | | |
|---|---|---|---|---|---|---|
| Gain (loss) on involuntary conversion of property, plant and equipment | 343 | (1,021) | — | — | — | — |
| (Loss) gain on sale of assets, net | — | 123 | 399 | — | — | — |
| Loss on impairment of property, plant and equipment | (18,155) | — | — | | | |
| Operating loss | (22,355) | (2,001) | (7,522) | (2,908) | (6,161) | (1,444) |
| Other income (expense) | | | | | | |
| Interest expense | (9,291) | (4,570) | (4,508) | (5,406) | (910) | (3,728) |
| Other income | — | — | — | — | — | 24 |
| Net loss before income tax benefit | (31,646) | (6,571) | (12,030) | (8,314) | (7,071) | (5,148) |
| Income tax benefit | 495 | — | — | — | — | — |
| Net loss from continuing operations | (31,151) | (6,571) | (12,030) | (8,314) | (7,071) | (5,148) |
| Discontinued operations | | | | | | |
| (Loss) income from operations of disposal groups, net of tax | (2,255) | 319 | 332 | (330) | 79 | (189) |
| Net loss | (33,406) | (6,252) | (11,698) | (8,644) | (6,992) | (5,337) |
| Net income attributable to non-controlling interests | 633 | 256 | — | — | — | — |
| Net loss attributable to the Partnership | $(34,039) | $(6,508) | $(11,698) | $(8,644) | $(6,992) | $(5,337) |
| General partner's interest in net loss | $(1,405) | $(129) | $(233) | $(173) | $(140) | |
| Limited partners' interest in net loss | $(32,634) | $(6,379) | $(11,465) | $(8,471) | $(6,852) | |
| | | | | | | |
| Limited partners' net loss per common unit: | | | | | | |
| Basic and diluted: | | | | | | |
| Loss from continuing operations | $(6.76) | $(0.73) | $(1.68) | $(1.60) | | |
| (Loss) income from discontinued operations | (0.24) | 0.03 | 0.04 | (0.06) | | |
| Net loss | $(7.00) | $(0.70) | $(1.64) | $(1.66) | $(3.13) | |
| Weighted average number of common units outstanding: | | | | | | |
| Basic and diluted (b) | 7,981 | 9,113 | 6,997 | 5,099 | 2,187 | |
| Statement of Cash Flow Data: | | | | | | |
| Net cash provided by (used in): | | | | | | |
| Operating activities | $17,223 | $18,348 | $10,432 | $13,791 | $(6,531) | $14,589 |
| Investing activities | (28,214) | (62,427) | (41,744) | (10,268) | (151,976) | (853) |
| Financing activities | 10,816 | 43,784 | 32,120 | (4,609) | 159,656 | (14,088) |
| Other Financial Data: | | | | | | |
| Adjusted EBITDA (c) | $31,904 | $18,847 | $20,785 | $18,154 | $3,434 | $10,931 |
| Gross margin (d) | 76,623 | 48,706 | 43,860 | 37,097 | 6,028 | 29,001 |
| Cash distribution declared per common unit | 1.75 | 1.73 | 0.70 | | | |
| Segment gross margin: | | | | | | |
| Gathering and Processing | 36,464 | 35,393 | 30,123 | 23,573 | 3,486 | 19,120 |
| Transmission | 32,408 | 13,313 | 13,737 | 13,524 | 2,542 | 9,881 |
| Terminals | 7,751 | — | — | — | — | — |
| Balance Sheet Data (At Period End): | | | | | | |
| Cash and cash equivalents | $393 | $576 | $871 | $63 | $1,149 | $149 |
| Accounts receivable and unbilled revenue | 28,827 | 23,470 | 20,963 | 22,850 | 19,776 | 8,756 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Property, plant and equipment, net | 312,510 | 223,819 | 170,231 | 146,808 | 146,226 | 205,126 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total assets | 382,075 | 256,696 | 199,551 | 173,229 | 174,470 | 250,162 |
| Current portion of long-term debt | 2,048 | — | — | 6,000 | — | — |
| Long-term debt | 130,735 | 128,285 | 66,270 | 50,370 | 61,000 | — |
| Operating Data: | | | | | | |
| Gathering and processing segment: | | | | | | |
| Throughput (MMcf/d) | 277.2 | 291.2 | 250.9 | 175.6 | 169.7 | 211.8 |
| Plant inlet volume (MMcf/d) (e) | 117.3 | 116.1 | 36.7 | 9.9 | 11.4 | 11.7 |
| Gross NGL production (Mgal/d)(e) | 52.0 | 49.9 | 54.5 | 34.1 | 38.2 | 39.3 |
| Gross condensate production (Mgal/d) (e) | 46.2 | 22.6 | 22.6 | — | — | — |
| Transmission segment: | | | | | | |
| Throughput (MMcf/d) | 644.7 | 398.5 | 381.1 | 350.2 | 381.3 | 357.6 |
| Firm transportation capacity reservation (MMcf/d) | 640.7 | 703.6 | 702.2 | 677.6 | 701.0 | 613.2 |
| Interruptible transportation throughput (MMcf/d) | 389.2 | 86.6 | 69.0 | 80.9 | 118.0 | 121.0 |
| Terminals segment: | | | | | | |
| Storage utilization | 96.2 % | — | — | — | — | — |

(a) Represents cash and non-cash costs related to our Long-Term Incentive Plan ("LTIP"). Of these amounts, $2.1 million, $1.8 million and $1.6 million, for the years ended December 31, 2013, 2012 and 2011, respectively, were non-cash expenses.

(b) 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 DERs were eliminated on June 9, 2011. There were no such unvested phantom units with DERs at December 31, 2011, or subsequent.

(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 gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read “— How We Evaluate Our Operations.”

(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.”

## 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 in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We are engaged in the business of gathering, treating, processing, fractionating and transporting natural gas through our ownership and operation of eleven gathering systems, two processing facilities, one fractionation facility, four terminal sites, three interstate pipelines and five intrastate pipelines. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Recently, we became an owner, developer and operator of petroleum, agricultural, and chemical liquid terminal storage facilities. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas and NGL markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 2,100 miles of pipelines that gather and transport approximately 1 Bcf/d of natural gas and operate approximately 1.3 million barrels of storage capacity across four marine terminal sites.

Significant financial highlights during the year ended December 31, 2013, include the following:

- For the year ended December 31, 2013, gross margin increased to $76.6 million or 57.3% compared to the same period in 2012;
- Incremental gross margin of $7.8 million, included in the increase disclosed above, for the year ended December 31, 2013, was a result of the Blackwater Acquisition, which represented a transaction between entities under common control and a change in reporting entity. Therefore we have accounted for Blackwater and our Terminals segment as if the transaction occurred April 15, 2013. Please read "Recent Events" below for more information;
- We distributed $13.2 million to our limited partner unitholders, or $1.75 per unit, for the year ended December 31, 2013 as compared to $1.73 per unit for the same period in 2012;
- We completed the Equity Restructuring. Please read "Recent Events" below for more information. On September 30, 2013, we received approximately $12.5 million from HPIP, which was used to repay outstanding borrowings under the credit agreement in connection with the Equity Restructuring;
- We issued, in a public offering, 2,568,712 common units representing limited partner interests in the Partnership at a price to the public of $22.47 per common unit. We used the net proceeds of $54.9 million to fund a portion of the purchase price for Blackwater; and
- On January 24, 2013, we entered into the second waiver to the credit facility that extended the waiver period with respect to the consolidated total leverage ratio to April 16, 2013. Through amendments and repayments of borrowings, we are in compliance with the consolidated total leverage ratio as of December 31, 2013. As of December 31, 2013, we had approximately $130.7 million of outstanding borrowings and approximately $64.5 million of available borrowing capacity.

Significant operational highlights during the year ended December 31, 2013, include the following:

- Throughput attributable to the Partnership totaled 921.9 MMcf/d for the year ended December 31, 2013, representing a 33.6% increase compared to the same period in 2012;
- Average gross condensate production totaled 46.2 Mgal/d for the year ended December 31, 2013, representing a 104.4% increase compared to the same period in 2012;
- Average gross NGL production totaled 52.0 Mgal/d for the year ended December 31, 2013, representing a 4.2% increase compared to the same period in 2012; and
- Effective April 15, 2013, our General Partner contributed the High Point System, consisting of 100% of the limited liability company interests in High Point Gas Transmission, LLC and High Point Gas Gathering, LLC. The High Point System consists of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana, in the Plaquemines and St. Bernard parishes, and the shallow water and deep shelf Gulf of Mexico, including the Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound zones.

Our Operations

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

- Gathering and Processing. Our Gathering and Processing segment provides “wellhead-to-market” services to producers of natural gas and oil, which include transporting raw natural gas from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas as well as NGLs to various markets and pipeline systems.
- Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include LDCs, utilities and industrial, commercial and power generation customers.
- Terminals. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including crude oil, bunker fuel, distillates, chemicals and agricultural products.

Gathering and Processing Segment

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

- Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed cash fee for gathering and processing and transporting natural gas.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.
- Percent-of-Proceeds Arrangements (“POP”). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, such as under our Toca contract, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas, such as for our interest in the Burns Point Plant. Our POP arrangements also often contain a fee-based component.
- Interest in the Burns Point Plant. We account for our interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our consolidated statement of operations, our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.
- Interest in the Chatom System. We account for our 92.2% undivided interest in the Chatom system pursuant to Accounting Standards Clarification (“ASC”) No. 810-10-65-1, Noncontrolling Interests. Under this method, revenues, expenses, gains, losses, net income or loss, and other comprehensive income are reported in the consolidated financial statements at the consolidated amounts, which include the amounts attributable to the partners' and the noncontrolling interests. The consolidated income statement shall separately present net income attributable to the partners' and the noncontrolling interests.

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

Transmission Segment

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

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

- Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an

identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

Terminals Segment

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

Contract Mix

Set forth below is a table summarizing our average contract mix for the years ended December 31, 2013 and 2012 (in millions):

| | For the Year Ended December 31, 2013 | | For the Year Ended December 31, 2012 | |
|---|---|---|---|---|
| | Segment Gross Margin | Percent of Segment Gross Margin | Segment Gross Margin | Percent of Segment Gross Margin |
| Gathering and Processing | | | | |
| Fee-based | $7.0 | 19.1 % | $8.5 | 24.0 % |
| Fixed margin | 1.6 | 4.5 % | 1.9 | 5.4 % |
| Percent-of-proceeds | 27.9 | 76.4 % | 25.0 | 70.6 % |
| Total | $36.5 | 100.0 % | $35.4 | 100.0 % |
| Transmission | | | | |
| Firm transportation | $10.6 | 32.6 % | $10.8 | 81.2 % |
| Interruptible transportation | 21.7 | 67.0 % | 1.9 | 14.3 % |
| Fixed margin | 0.1 | 0.4 % | 0.6 | 4.5 % |
| Total | $32.4 | 100.0 % | $13.3 | 100.0 % |
| Terminals (a) | | | | |
| Firm storage | $7.8 | 100.0 % | $— | — % |
| Total | $7.8 | 100.0 % | $— | — % |

(a) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013.

How We Evaluate Our Operations

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

Throughput Volumes

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

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

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

Gross Margin and Segment Gross Margin

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

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

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

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

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.

Effective October 1, 2012, we changed our segment gross margin measure to exclude construction, operating and maintenance agreement (“COMA”) income. For the year ended December 31, 2012, $0.7 million and $2.7 million in COMA income was excluded from our Gathering and Processing segment gross margin and our Transmission segment gross margin, respectively.

Direct Operating Expenses

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

Adjusted EBITDA

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

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

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

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 was $0.4 million for the year ended December 31, 2011. Further, we made a change to the calculation to exclude COMA income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the year ended December 31, 2011, was $0.9 million.

Note About Non-GAAP Financial Measures

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

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

The following table reconciles the non-GAAP financial measures of gross margin used by management to Net (loss) income attributable to the Partnership, their most directly comparable GAAP measure, for each of the three years ended December 31, 2013 (in thousands):

| | For the Year ending December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Reconciliation of Gross Margin to Net loss attributable to the Partnership | | | |
| Gathering and processing segment gross margin | $36,464 | $35,393 | $30,123 |
| Transmission segment gross margin | 32,408 | 13,313 | 13,737 |
| Terminals segment gross margin (a) | 7,751 | — | — |
| Total gross margin | 76,623 | 48,706 | 43,860 |
| Plus: | | | |
| Gain (loss) on commodity derivatives | 28 | 3,400 | (5,450) |
| Less: | | | |
| Direct operating expenses (b) | 27,473 | 16,798 | 11,419 |
| Selling, general and administrative expenses | 21,402 | 14,309 | 11,082 |
| Advisory services agreement termination fee | — | — | 2,500 |
| Transaction expenses | — | — | — |
| Equity compensation expense | 2,094 | 1,783 | 3,357 |
| Depreciation, amortization and accretion expense | 29,999 | 21,284 | 20,449 |
| Gain on acquisition of assets | — | — | (565) |
| (Gain) loss on involuntary conversion of property, plant and equipment | (343) | 1,021 | — |
| Gain on sale of assets | — | (123) | (399) |
| Loss on impairment of property, plant and equipment | 18,155 | — | — |
| Interest expense | 9,291 | 4,570 | 4,508 |
| Other, net (c) | 226 | (965) | (1,911) |
| Income tax benefit | (495) | — | — |
| Income (loss) from operations of disposal groups, net of tax | 2,255 | (319) | (332) |
| Net income attributable to noncontrolling interest | 633 | 256 | — |
| Net loss attributable to the Partnership | $(34,039) | $(6,508) | $(11,698) |

(a) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013.

(b) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $14.2 million and Transmission segment direct operating expenses of $13.3 million for the year ended December 31, 2013. Direct operating expenses related to our Terminals segment of $2.1 million are included within the calculation of Terminals segment gross margin.

(c) Other, net includes realized gain (loss) on commodity derivatives of $1.1 million, $2.4 million and $(1.9) million and COMA income of $0.8 million, $3.4 million and zero for the year ended December 31, 2013, 2012 and 2011, respectively.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Reconciliation of Adjusted EBITDA to Net loss attributable to the Partnership | | | |
| Net loss attributable to the Partnership | $(34,039) | $(6,508) | $(11,698) |
| Add: | | | |
| Depreciation, amortization and accretion expense | 29,999 | 21,284 | 20,449 |
| Interest expense | 7,850 | 4,570 | 4,508 |
| Debt issuance costs | 2,113 | 1,564 | — |
| Realized loss on early termination of commodity derivatives | — | — | 2,998 |
| Realized loss on commodity put purchase costs | — | — | 308 |
| Unrealized (gain) loss on derivatives, net | 1,495 | (992) | 541 |
| Non-cash equity compensation expense | 2,094 | 1,783 | 1,607 |
| Advisory services agreement termination fee | — | — | 2,500 |
| Special distribution to holders of LTIP phantom units | — | — | 1,624 |
| Transaction expenses | 3,987 | — | 282 |
| Impairment on property, plant and equipment | 18,155 | — | — |
| Loss on impairment of noncurrent assets held for sale | 2,400 | — | — |
| Deduct: | | | |
| Income tax benefit | 847 | — | — |
| COMA income | 843 | 3,373 | 879 |
| Straight-line amortization of put costs (a) | 119 | 291 | 409 |
| OPEB plan net periodic benefit (cost) | 73 | 88 | 82 |
| Gain (loss) on acquisition of assets | — | — | 565 |
| Gain (loss) on involuntary conversion of property, plant and equipment | 343 | (1,021) | — |
| Gain (loss) on sale of assets, net | (75) | 123 | 399 |
| Adjusted EBITDA | $31,904 | $18,847 | $20,785 |

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

Items Affecting the Comparability of Our Financial Results

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

- On December 17, 2013, we completed the Blackwater Acquisition. The acquisition of Blackwater represents a transaction between entities under common control and a change in reporting entity. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period or date of common control. Therefore, net assets received were recorded at their historical book value of $22.7 million as of the date common control was established, which is April 15, 2013;
- On April 15, 2013, our General Partner contributed the High Point System;
- On July 1, 2012, we acquired an 87.4% undivided interest in the Chatom system from affiliates of Quantum Resources Management, LLC. The acquisition fair value of consideration of $51.4 million includes a credit associated with the cash flow the Chatom Assets generated between January 1, 2012, and the effective date of July 1, 2012;
- On October, 2013, we acquired an additional 4.8% undivided interest in the Chatom system, increasing our ownership of the Chatom system to a total of 92.2%; and
- 

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

From 2012 through 2013, the US and global economy experienced a significant economic recovery from the recession lows from 2008 through 2011. Economic activity has increased, US unemployment rates have decreased, and the US and global stock markets have experienced significant recoveries. In this period of time, US domestic oil and natural gas production has increased substantially as a result of technologies that improved the recovery of hydrocarbons from unconventional formations, primarily oil shale. The global economic recovery has caused US oil and NGL prices to increase from low prices in 2012 as US export capability has increased. Natural gas prices have also experienced a recovery from the previous lows as consumption continues to increase and producers move production rigs away from dry natural gas basins. However, recently, as a result of abnormally cold weather, spot natural gas prices have reached record high prices.

We expect global NGL and oil prices to remain at current levels in the near term as global economies continue to increase petroleum consumption. However, due to the significant increase in production in the US, we expect regional pricing to vary as regional transportation and processing constraints emerge. In the near term, we expect natural gas prices to remain low as production levels continue to increase above consumption demand until the US has the ability to export natural gas.

We believe there will continue to be opportunities to invest in new infrastructure projects that are required to handle the increases in US hydrocarbon production, particularly in parts of the country that historically have not had significant oil and gas production. We also believe we will continue to have the option to purchase additional infrastructure around our existing asset base as producers and midstream companies divest of their assets in the Gulf Coast and southeastern regions of the US to focus on shale infrastructure.

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 26.0 trillion cubic feet, or Tcf, in 2013, compared to approximately 25.5 Tcf in 2012, representing an increase of approximately 2.0%. Domestic production of natural gas grew from approximately 25.3 Tcf in 2012 to approximately 25.6 Tcf in 2013, or a 1.2% increase. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States, representing approximately 60.0% of the total natural gas consumed in the United States during 2013. In particular, based on a report by the EIA, electric generation natural gas demand is expected to grow from 9.3 Tcf in 2012 to 11.2 Tcf in 2040 as a result of an expected retirement of coal-fired generation capacity. According to the EIA, domestic crude oil production was approximately 7.5 million barrels per day, or MMBbl/d, in 2013, compared to approximately 6.5 MMBbl/d in 2012, representing an increase of approximately 15.4%. 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 oil with associated natural gas, such as on our High Point, Bazor Ridge, Chatom and PVA systems, will remain active. We also believe that the current relatively low natural gas price environment will encourage the development of new industrial facilities that consume natural gas, which will benefit our transmission systems that are strategically located next to inland waterways, such as our AlaTenn and Midla complexes. 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.

Credit markets continue to experience near-record lows, which we believe will continue through 2014; however, if monetary policy begins to tighten, our interest rates on floating rate debt facilities and future offerings in the debt capital markets could be higher. An increase in financing costs may affect yield requirements of investors who invest in our common units.

Our expectations are based on assumptions 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.
Recent Events

Equity Restructuring

Effective August 9, 2013, we entered into an Equity Restructuring Agreement with our General Partner and HPIP. As part of the Equity Restructuring Agreement, our 4,526,066 subordinated units and previous incentive distribution rights ("IDRs") (all of which were owned by our General Partner, which is controlled by HPIP) were combined into and restructured as a new class of IDRs. Upon the issuance of the new IDRs, the subordinated units and former IDRs were cancelled. Until the execution of the Settlement agreement described below between us, HPIP, our General Partner and AIM Midstream Holdings, in which the allocation of IDRs was further modified, the new IDRs were allocated 85.02% to HPIP and 14.98% to our General Partner in accordance with each party's respective capital contribution to such combination and restructuring. The new IDRs entitle the holders of our incentive distribution rights to receive 48% of any quarterly cash distributions from available cash after our common unitholders have received the full minimum quarterly distribution ($0.4125 per unit) for each quarter plus any arrearages from prior quarters (of which there are currently none).

The Equity Restructuring Agreement also provided for the issuance of warrants to our general partner to purchase up to 300,000 of our common units at an exercise price of $0.01 per common unit. These warrants were cancelled on November 11, 2013, effective as of August 29, 2013. These warrants were exercisable on the later of (i) 18 months from the Equity Restructuring completion date and (ii) the date that the volume weighted average trading price of our common units on the New York Stock Exchange exceeded $25.00 for 30 consecutive trading days. The warrants contained customary anti-dilution and other protections. These warrants were being held by our general partner for subsequent conveyance to AIM Midstream Holdings, LLC, the owner of the Class B interest of our general partner, upon release of certain funds from escrow. In connection with the cancellation of the warrants on November 11, 2013, our general partner authorized the issuance of replacement warrants in an amount and on terms substantially identical to the cancelled warrants, with such issuance (unless otherwise ordered by a court) to be made to our general partner or HPIP depending upon the circumstances surrounding the release of cash from an escrow account deposited in connection with the Purchase Agreement entered into between HPIP and AIM Midstream Holdings on April 15, 2013.

Following the announcement of the Equity Restructuring Agreement, AIM Midstream Holdings filed an action in Delaware Chancery Court against HPIP and our General Partner seeking either rescission of the Equity Restructuring Agreement or, in the alternative, monetary damages. On February 5, 2014, we, HPIP, and our General Partner entered into the Settlement with AIM Midstream Holdings regarding the action filed in Delaware Chancery Court. Under the Settlement, among other things:

- HPIP and AIM Midstream Holdings amended the limited liability company agreement of our General Partner (the "LLC Amendment") to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP's sharing percentage is now 95% and AIM Midstream Holdings's Sharing Percentage is 5%;

- HPIP transferred all of the 85.02% of the Partnership's outstanding new IDRs held by HPIP to the General Partner such that the General Partner owns 100% of the outstanding new IDRs; and

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

Blackwater Acquisition

On December 17, 2013, the Partnership completed the Blackwater Acquisition, pursuant to an Agreement and Plan of Merger with ALB, an affiliate of ArcLight, Blackwater and Blackwater Merger Sub, LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of the Partnership. Blackwater owns and operates 1.3 million barrels of storage capacity across four terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland. These terminal sites provide storage services to support various commercial customers, including commodity brokers, refiners, and chemical manufacturers, to store a range of products, including crude oil, bunker fuel, distillates, chemicals and agricultural products. The consideration for the Blackwater Acquisition was financed with the net proceeds of the Partnership's December 2013 equity offering and borrowings under our credit facility.

ArcLight is an affiliate of HPIP, which owns a 95% interest in our general partner. Accordingly, the conflicts committee of our general partner's Board of Directors concluded that the Blackwater Acquisition is fair and reasonable to us and our public common unitholders, approved the related merger agreement and the transactions contemplated thereby, and recommended that our general partner's Board of Directors adopt and approve the merger agreement and transactions contemplated thereby. The conflicts committee, a committee of independent members of our general partner's Board of Directors, retained independent legal and financial advisors to assist it in evaluating the merger agreement and the transactions contemplated thereby.

Completion of PVA Acquisition

On January 31, 2014, the Partnership acquired, from Penn Virginia Corporation ("PVA"), approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The consideration for the PVA Asset Acquisition was financed with the net proceeds of the Partnership's January 2014 equity offering and the proceeds from the issuance to our General Partner of 1,168,225 Series B PIK Units representing series B limited partnership interests in the Partnership. The Series B PIK Units have the right to share in distributions from the Partnership on a pro rata basis with holders of the Partnership's common units and will convert into common units on a one-for-one basis on the second anniversary of the initial issuance. The conflicts committee of our General Partner's board of directors approved the Series B PIK Unit issuance and the transactions contemplated thereby.

Results of Operations — Combined Overview

For the year ended December 31, 2013, gross margin increased by $27.9 million, or 57.3%, to $76.6 million compared to the same period in 2012. The increase in gross margin was largely a result of (i) an increase of gross margin in our Transmission segment of $19.1 million as a result of incremental gross margin associated with our High Point System of $19.7 million, (ii) gross margin in our Gathering and Processing segment of $1.1 million due to incremental gross margin associated with our Chatom System of $6.4 million offset by lower throughput volumes of 14.0 Mcf/d associated with our systems in the Gathering and Processing segment, and (iii) the inclusion of gross margin of $7.8 million from our Terminals segment.

We distributed $13.2 million to our limited partner unitholders, or $1.75 per unit, during the year ended December 31, 2013.

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

| | For the Year Ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| Statement of Operations Data: | | | |
| Revenue | $292,626 | $194,843 | $233,169 |
| Realized gain (loss) on early termination of commodity derivatives | — | — | (2,998) |
| Gain (loss) on commodity derivatives | 28 | 3,400 | (2,452) |
| Total revenue | 292,654 | 198,243 | 227,719 |
| Operating expenses: | | | |
| Purchases of natural gas, NGLs and condensate | 214,149 | 145,172 | 187,398 |
| Direct operating expenses | 29,553 | 16,798 | 11,419 |
| Selling, general and administrative expenses | 21,402 | 14,309 | 11,082 |
| Advisory services agreement termination fee | — | — | 2,500 |
| Transaction expenses | — | — | — |
| Equity compensation expense (a) | 2,094 | 1,783 | 3,357 |
| Depreciation, amortization and accretion expense | 29,999 | 21,284 | 20,449 |
| Total operating expenses | 297,197 | 199,346 | 236,205 |
| Gain (loss) on acquisition of assets | — | — | 565 |
| Gain (loss) on involuntary conversion of property, plant and equipment | 343 | (1,021) | — |
| Gain (loss) on sale of assets, net | — | 123 | 399 |
| Loss on impairment of property, plant and equipment | (18,155) | — | — |
| Operating income (loss) | (22,355) | (2,001) | (7,522) |
| Other income (expenses) | | | |
| Interest expense | (9,291) | (4,570) | (4,508) |
| Net income (loss) before income tax benefit | (31,646) | (6,571) | (12,030) |
| Income tax benefit | 495 | — | — |
| Net (loss) income from continuing operations | (31,151) | (6,571) | (12,030) |
| Discontinued operations | | | |
| (Loss) income from operations of disposal groups, net of tax | (2,255) | 319 | 332 |
| Net income (loss) | (33,406) | (6,252) | (11,698) |
| Net income (loss) attributable to non-controlling interests | 633 | 256 | — |
| Net income (loss) attributable to the Partnership | $(34,039) | $(6,508) | $(11,698) |
| | | | |
| Other Financial Data: | | | |
| Gross margin (b) | $76,623 | $48,706 | $43,860 |
| Adjusted EBITDA (c) | $31,904 | $18,847 | $20,785 |

(a) Represents cash and non-cash costs related to our Long-Term Incentive Plan ("LTIP"). Of these amounts, $2.1 million, $1.8 million and $1.6 million, for the years ended December 31, 2013, 2012 and 2011, respectively, were non-cash expenses.

(b) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and 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."

Year ended December 31, 2013, compared to year ended December 31, 2012

Revenue. Our revenue for the year ended December 31, 2013 was $292.6 million compared to $194.8 million for the year ended December 31, 2012. This increase of $97.8 million was primarily due to the following -

- Natural gas revenues increased $36.6 million as a result of (i) higher realized natural gas prices of $4.03/Mcf, an increase of $1.05/Mcf, or 35.2%, period over period, and (ii) increased natural gas sales volumes of 6.0% period over period;
- NGL revenues increased $3.2 million as a result of higher NGL volumes associated with our elective processing agreement and by higher gross NGL production volumes of 2.1 Mgal/d due to improved volumes from our Gathering and Processing segment offset by lower realized NGL prices of $0.90/gal, a decrease of $0.18/gal period over period;
- Condensate revenues increased $22.4 million as a result of higher condensate production of 23.6 Mgal/d while realized condensate prices remained consistent period over period;
- Transmission revenues from the transportation of natural gas increased $27.8 million primarily as a result of incremental revenue of $30.4 million associated with our High Point System; and
- Storage and other revenues of $9.8 million from the inclusion of our Terminals segment.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2013, were $214.1 million compared to $145.2 million in the year ended December 31, 2012. This increase of $68.9 million was primarily due to higher purchase costs associated with natural gas due to higher realized natural gas prices, higher natural gas purchase volumes and higher condensate and NGL production related to POP contracts associated with owned processing plants in our Gathering and Processing segment, partially offset by lower realized NGL prices associated with our POP contracts.

Gross Margin. Gross margin for the year ended December 31, 2013, was $76.6 million compared to $48.7 million for the year ended December 31, 2012. This increase of $27.9 million was primarily due to (i) higher gross margin in our Transmission segment of $19.1 million as a result of incremental gross margin associated with our High Point System of $19.7 million and (ii) higher gross margin in our Gathering and Processing segment of $1.1 million due to improved condensate production of 23.6 MMcf/d, or 104.4%, partially offset by lower margins associated with our POP and elective processing agreements in the segment and (iii) contributed gross margin of $7.8 million associated with our Terminals segment.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2013, were $29.6 million compared to $16.8 million in the year ended December 31, 2012. This increase of $12.8 million was primarily due to: (i) $2.5 million of additional salaries, wages and benefits associated with the contributed High Point System; (ii) $2.4 million of costs associated with our property and casualty insurance; (iii) $1.7 million associated with additional aerial inspections of our Transmission segment; and (iv) $2.1 million associated with our Terminals segment.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the year ended December 31, 2013, were $21.4 million compared to $14.3 million for the year ended December 31, 2012. This increase of $7.1 million was primarily due to (i) higher transaction costs of $3.6 million associated with the Equity Restructuring and acquisitions of the High Point System and Blackwater; and (ii) incremental costs of $2.9 million associated with our Terminals segment.

Equity Compensation Expense. Compensation expense related to our LTIP for the year ended December 31, 2013, was $2.1 million compared to $1.8 million for the year ended December 31, 2012. This increase of $0.3 million was primarily due to the acceleration of additional unit based awards granted in 2012.

Depreciation Expense. Depreciation expense in the year ended December 31, 2013, was $30.0 million compared to $21.3 million for the year ended December 31, 2012. This increase of $8.7 million was due to depreciation associated with newly acquired facilities and capital projects placed into service during the period.

Loss on Impairment of Property, Plant and Equipment. During the second quarter of 2013, management determined to change its commercial approach towards certain non-strategic gathering and processing assets. As a result, asset impairment charges of $17.0 million were recorded during the second quarter of 2013. In addition, during the first quarter of 2014, the board of directors of our General Partner gave approval to the management team to pursue the sale of certain gathering and processing assets for an amount less than the carrying value of the assets. As a result, these gathering and processing assets were written down by $3.0 million during the fourth quarter of 2013. There was no impairment charge necessary in the comparative periods presented.

Interest Expense. Interest expense for the year ended December 31, 2013, was $9.3 million compared to $4.6 million for the year ended December 31, 2012. This increase of $4.7 million was primarily due to (i) the increase in borrowings under our credit facility and an increase to our weighted average interest rate of 0.42% as a result of the Fourth Amendment to our Credit Agreement and (ii) incremental interest expense of $1.4 million associated with our Terminals segment.

Year ended December 31, 2012, compared to year ended December 31, 2011

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Revenue. Our revenue for the year ended December 31, 2012, was $194.8 million compared to $233.2 million for the year ended December 31, 2011. This decrease of $38.4 million was primarily due to the following -

- Natural gas revenues decreased $25.8 million as a result of a decline in realized natural gas prices of $1.12/Mcf along with a decrease in natural gas sales volumes of approximately 2.0 Mmcf attributable to production shut-ins caused by Hurricane Isaac;
- NGL revenues decreased $8.8 million as a result of a decline in realized NGL prices of $0.24/gal and a decrease in NGL sales volumes of 1.3 m/gal due to a turnaround taking longer than anticipated as a result of unscheduled repairs and upgrades that slowed the turnaround process but are expected to deliver long-term improved efficiencies at our Bazor Ridge processing facility offset by an increase in volumes from the newly acquired Chatom system;
- Transmission revenues from the transportation of natural gas decreased $13.5 million as a result of declines in realized natural gas prices on our fixed margin contracts of $1.26/Mcf amounting to $13.5 million and a decrease in sales volumes of 5% period over period; and
- Condensate revenues increased $13.8 million as a result of an increase in condensate sales volumes of 5.7 m/gal due to the newly acquired Chatom system while realized condensate prices remained consistent period over period.

Realized gain (loss) on early termination of commodity derivatives. We recognized a one-time charge of $3.0 million resulting from the unwind and reset of our commodity derivative 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, 2012, were $145.2 million compared to $187.4 million in the year ended December 31, 2011. This decrease of $42.2 million was primarily due to lower natural gas and NGL sales volumes and related realized prices related to POP contracts associated with owned processing plants in our Gathering and Processing and Transmission segments. This decrease was partially offset by higher condensate purchase costs in our Gathering and Processing segment.

Gross Margin. Gross margin for the year ended December 31, 2012, was $48.7 million compared to $43.9 million for the year ended December 31, 2011. This increase of $4.8 million was primarily due to higher throughput volume and associated condensate production from owned processing plants in our Gathering and Processing segment. This was a result of our recent acquisitions of the Burns Point Plant, effective November 1, 2011, and of the Chatom system, effective July 1, 2012, which contributed incremental gross margin of $3.7 million and $5.7 million, respectively. These increases were offset by a decline in gross margin from our Bazor Ridge and Quivira systems due to unscheduled repairs and upgrades that slowed the turnaround process amounting to $0.7 million and declined in volumes during the third and fourth quarters of 2012 as a result of a producer's work on one of its platforms amounting to approximately $2.0 million, respectively.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2012, were $16.8 million compared to $11.4 million in the year ended December 31, 2011. This increase of $5.4 million was primarily due to: (i) $0.7 million incremental costs related to additional insurance premiums; (ii) $1.8 million of added expenses associated with our 50% undivided interest in the operating costs incurred at the Burns Point Plant; and (iii) $2.9 million of added expenses associated with our new acquired Chatom system.

Selling, General and Administrative Expenses. SG&A expenses for the year ended December 31, 2012, were $14.3 million compared to $11.1 million for the year ended December 31, 2011. This increase of $3.2 million was primarily due to: (i) $1.5 million of incremental personnel costs, recruiting fees and related benefits necessary to operate and grow a public company; (ii) $0.7 million in additional legal expenses associated with SEC and other regulatory compliance; (iii) $0.8 million of incremental accounting, auditing and tax costs associated with our acquisition of the Chatom Assets and shelf registration statement; and (iv) $0.4 million of incremental costs associated with outside services and contract labor to assist in maintaining and maximizing operational efficiency of our systems and internal controls over financial reporting.

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

Equity Compensation Expense. Compensation expense related to our LTIP for the year ended December 31, 2012, was $1.8 million compared to $3.4 million for the year ended December 31, 2011. This decrease of $1.6 million was primarily due to 2011 buy-out of distribution equivalent rights (“DERs”) associated with unvested phantom units at a cost of $1.5 million, a payment to holders of unvested phantom units without DERs of $0.1 million, increased amortization of $0.1 million associated with March 2011 phantom unit grants, offset 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 DERs that did not occur in the year ended December 31, 2012.

Depreciation Expense. Depreciation expense in the year ended December 31, 2012, was $21.3 million compared to $20.4 million for the year ended December 31, 2011. This increase of $0.9 million was due to depreciation associated with newly acquired facilities and capital projects placed into service during the period.

Results of Operations — Segment Results

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

| | For the Year Ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| Segment Financial and Operating Data: | | | |
| Gathering and Processing segment | | | |
| Financial data: | | | |
| Revenue | $192,446 | $145,714 | $160,953 |
| Realized gain (loss) on early termination of commodity derivatives | — | — | (2,998) |
| Gain (loss) on commodity derivatives, net | 28 | 3,400 | (2,452) |
| Total revenue | 192,474 | 149,114 | 155,503 |
| Purchases of natural gas, NGLs and condensate | 156,334 | 108,656 | 134,369 |
| Direct operating expenses | 14,214 | 11,767 | 6,199 |
| Other financial data: | | | |
| Segment gross margin | $36,464 | $35,393 | $30,123 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 277.2 | 291.2 | 250.9 |
| Average plant inlet volume (MMcf/d) (a) | 117.3 | 116.1 | 36.7 |
| Average gross NGL production (Mgal/d) (a) | 52.0 | 49.9 | 54.5 |
| Average gross condensate production (Mgal/d) (a) | 46.2 | 22.6 | 6.8 |
| Average realized prices: | | | |
| Natural gas ($/MMcf) | $4.03 | $2.98 | $4.09 |
| NGLs ($/gal) | $0.90 | $1.08 | $1.32 |
| Condensate ($/gal) | $2.29 | $2.30 | $2.41 |
| Transmission segment | | | |
| Financial data: | | | |
| Total revenue | $90,377 | $52,529 | $66,766 |
| Purchases of natural gas, NGLs and condensate | 57,815 | 36,516 | 53,029 |
| Direct operating expenses | 13,259 | 5,031 | 5,220 |
| Other financial data: | | | |
| Segment gross margin | $32,408 | $13,313 | $13,737 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 644.7 | 398.5 | 381.1 |
| Average firm transportation - capacity reservation (MMcf/d) | 640.7 | 703.6 | 702.2 |
| Average interruptible transportation - throughput (MMcf/d) | 389.2 | 86.6 | 69.0 |
| Terminals segment (b) | | | |
| Financial data: | | | |
| Total revenue | $9,831 | $— | $— |
| Direct operating expenses | 2,080 | — | — |
| Other financial data: | | | |
| Segment gross margin | $7,751 | $— | $— |
| Operating data: | | | |
| Storage utilization | 96.2 % | — | — |

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

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(b) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013.

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2013, was $192.4 million compared to $145.7 million for the year ended December 31, 2012. This increase of $46.7 million was primarily due to the following -

- Higher realized natural gas prices of 35.2% offset by lower realized NGL prices of 16.7% period over period as a result of variable commodity prices;
- Higher average gross condensate production amounting to 23.6 Mgal/d, or an increase of 104.4% period over period as a result of our increased production at our Chatom System;
- Higher NGL volume associated with our elective processing agreement and average gross NGL production amounting to 2.1 Mgal/d, or a net increase of 4.2% period over period, as a result of our improved production of 10.7 Mgal/d on our Chatom System; offset by
- Lower average natural gas throughput volumes amounting to 14.0 MMcf/d or 4.8% period over period primarily as a result of lower natural gas throughput volumes of 11.5 MMcf/d on our Quivira system.

Gain (loss) on commodity derivatives, net. Gain (loss) on commodity derivatives, net presents our commodity derivatives which was comprised of financial swaps, collars and option contracts used to mitigate commodity price risk that have settled in 2013 or will be settled in 2014 decreased $3.4 million period over period due to holding net short positions in a rising commodity price market. For a discussion of our commodity derivative positions, please read "Item 3. Quantitative and Qualitative Disclosures about Market Risk."

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2013, were $156.3 million compared to $108.7 million for the year ended December 31, 2012. This increase of $47.6 million was primarily due to higher purchase costs associated with natural gas due to higher realized natural gas prices, higher natural gas purchase volumes and higher condensate and NGL production related to POP contracts associated with owned processing plants in our Gathering and Processing segment, partially offset by lower realized NGL prices associated with our POP contracts.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $36.5 million compared to $35.4 million for the year ended December 31, 2012. This increase of $1.1 million was primarily due to the following -

- Incremental gross margin of $6.4 million associated with higher average condensate production of 21.3 Mgal/d as a result of the Chatom system; offset by
- Lower gross margins of $1.9 million associated with our Quivira system which saw a decline in volumes of 11.5 Mmcf/d on one of its offshore pipeline systems during 2013;
- A decrease in realized gains of $2.2 million period over period on our commodity derivatives which comprised of financial swaps and option contracts which were used to mitigate commodity price risk that settled in 2013.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $14.2 million compared to $11.8 million for the year ended December 31, 2012. This increase of $2.4 million was primarily due to (i) chemicals and maintenance costs of $1.1 million; and (ii) incremental operating costs associated with our 92.2% undivided interest in the Chatom System acquired July 2012 amounting to $1.5 million.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2013, was $90.4 million compared to $52.5 million for the year ended December 31, 2012. This increase of $37.9 million in revenue was primarily due to the following -

- Higher realized natural gas prices on our fixed margin contracts of $0.87/Mcf amounting to $11.7 million; and
- Total natural gas throughput volumes on our Transmission systems for the year ended December 31, 2013, was 644.7 MMcf/d compared to 398.5 MMcf/d for the year ended December 31, 2012, representing a 61.7% increase period over period primarily due to the contribution of the High Point System, effective April 15, 2013, amounting to $30.4 million.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2013, were $57.8 million compared to $36.5 million for the year ended December 31, 2012. This increase of $21.3 million was primarily due to higher realized natural gas prices, which resulted in higher natural gas purchase costs associated with our

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fixed margin agreements on MLGT and Midla amounting to $9.2 million and (ii) incremental natural gas costs associated with imbalances and cash-outs in connection with our High Point System of $12.6 million.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $32.4 million compared to $13.3 million for the year ended December 31, 2012. This increase of $19.1 million was primarily due to incremental gross margin on our High Point System of $19.7 million offset by lower gross margin on our remaining assets of $0.6 million.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $13.3 million compared to $5.0 million for the year ended December 31, 2012. This increase of $8.3 million is primarily due to our High Point System amounting $6.6 million.

Terminals Segment

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

Revenue. Segment total revenue for the year ended December 31, 2013, was $9.8 million which consisted of fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $2.1 million which consisted of direct labor, general materials and supplies and direct overhead.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $7.8 million which is defined as segment total revenue less direct operating expense.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2012, was $145.7 million compared to $161.0 million for the year ended December 31, 2011. This decrease of $15.3 million was primarily due to the following -

- A decline in realized natural gas prices of 27%, realized NGL prices of 18% and realized condensate prices of 5% period over period as a result of variable commodity prices;
- A decline in average gross NGL production amounting to 4.6 Mgal/d period over period as a result of extended turnaround efforts at our Bazor Ridge system during the fourth quarter, offset by;
- An increase in average throughput amounting to 40.4 MMcf/d or 16% period over period as a result of having a full year's operational impact of our 50% undivided interest in the Burns Point Plant offset by declines in average throughput associated with our Quivira and Gloria systems as well as production shut-ins surrounding our Gulf Coast systems during the third quarter as a result of Hurricane Isaac; and
- A significant increase in average gross condensate production amounting to 15.7 Mgal/d period over period as a result of our newly acquired Chatom system in the third quarter of 2012.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2012, were $108.7 million compared to $134.4 million for the year ended December 31, 2011. This decrease of $25.7 million was primarily due to lower natural gas and NGL sales volumes and related realized commodity prices related to POP contracts associated with our Bazor Ridge system. This decrease was partially offset by higher condensate sales volumes associated with the newly acquired Chatom system, effective July 1, 2012, and higher NGL sales volumes at the Burns Point Plant.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2012, was $35.4 million compared to $30.1 million for the year ended December 31, 2011. This increase of $5.3 million was primarily due to the following:

- Incremental gross margin of $5.6 million associated with higher average condensate production of 17.1 Mgal/d as a result of the newly acquired Chatom system, effective July 1, 2012;
- Incremental gross margin of $2.5 million associated with higher average throughput of 76.4 Mcf/d and NGL production of 7.7 Mgal/d as a result of having a full year of operational results of the Burns Point Plant, acquired effective November 1, 2011, offset by lower gross margins of $1.3 million associated with our Quivira system which saw a decline in volumes on one of its offshore pipeline systems during the third and fourth quarters of 2012 as a

result of a producer completing work on one of its platforms;

- A decline in gross margin of $1.8 million associated with lower NGL production of 14.9 Mgal/d at our Bazor Ridge processing plant due to a turnaround taking longer than anticipated as a result of unscheduled repairs and upgrades that slowed the turnaround process but are expected to deliver long-term, improved efficiencies at our Bazor Ridge processing facility;
- Gross margins associated with facilities damaged and/or impacted by production shut-ins as a result of the named windstorm Hurricane Isaac were estimated to approximately $0.8 million are covered by our insurance carrier; and
- An increase in realized gains of $4.3 million period over period on our commodity derivatives which comprised of financial swaps and option contracts which were used to mitigate commodity price risk that settled in 2012.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2012, were $11.8 million compared to $6.2 million for the year ended December 31, 2011. This increase of $5.6 million was primarily due to (i) $0.6 million incremental costs related to additional insurance premiums; (ii) $1.7 million of added expenses associated with operating costs incurred at the Burns Point Plant; and (iii) $2.5 million of added expenses associated with operating costs incurred at our Chatom system.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2012, was $52.5 million compared to $66.8 million for the year ended December 31, 2011. This decrease of $14.3 million in revenue was primarily due to the following:

- A decline in realized natural gas prices on our fixed margin contracts of $1.26/Mcf along with a decline in sales volumes of 5% amounting to $13.5 million period over period;
- Total natural gas throughput on our Transmission systems for the year ended December 31, 2012, was 398.5 MMcf/d compared to 381.1 MMcf/d for the year ended December 31, 2011, representing a 5% increase period over period; and
- Lower transportation fees associated with our interruptible transportation contracts offset by an increase in throughput of 17.5 MMcf/d amounting to $0.5 million period over period.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2012, were $36.5 million compared to $53.0 million for the year ended December 31, 2011. This decrease of $16.5 million was primarily due to a decrease in our purchases costs associated with fixed margin contracts as a result of a decline in natural gas market prices and sales volumes.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2012, was $13.3 million compared to $13.7 million for the year ended December 31, 2011. This decrease of $0.4 million was primarily associated with a slight change to our contract mix of fixed margin, firm and interruptible transportation contracts offset by a slight increase in throughput volumes period over period.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2012, were $5.0 million compared to $5.2 million for the year ended December 31, 2011. This decrease of $0.2 million was primarily due to lower property taxes incurred period over period.

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, 2013, were our cash on hand and availability under our credit facility. As of December 31, 2013, our available liquidity was $64.9 million, comprised of cash on hand of $0.4 million and $64.5 million available under our credit facility. As of March 7, 2014, our available liquidity was $67.7 million. We believe that cash generated from operating cash flows and liquidity will be sufficient to meet our short-term working capital requirements, medium-term capital expenditure requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, issuing equity and additional debt financing; in addition, we would reduce spending in certain areas, such as capital expenditures, as necessary.

In December 2013, we issued 2,568,712 common units at a price to the public of $22.47 per unit. We received proceeds of $54.9 million, net of offering costs.

In January 2014, we issued 3,400,000 common units at a price to the public of $26.75 per unit. We received proceeds of $87.3 million, net of offering costs.

Changes in natural gas, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A. "Quantitative and Qualitative Disclosures about Market Risk."

The counterparties to certain of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Our Credit Facility

We are required to comply with certain financial covenants and ratios in our credit facility. As of December 31, 2012, the total leverage ratio test, one of the primary financial covenants that we are required to maintain under our credit facility, was not to exceed 4.50 times. At December 31, 2012, our total indebtedness was approximately $128.3 million, which caused our total leverage to EBITDA ratio to be approximately 5.70-to-1.00. As a result, on December 26, 2012, the Partnership entered into the Third Amendment and Waiver to the Partnership's Credit Agreement (the "Credit Agreement"), dated as of December 26, 2012 (the "Third Amendment"). The Third Amendment provided for a waiver of the Partnership's compliance with the Consolidated Total Leverage Ratio with respect to the quarter ending December 31, 2012 and subsequently extended to April 15, 2013. The Third Amendment also required the Partnership to provide certain financial and operating information of the Partnership on a monthly basis for 2013 and for any month after 2013 in which the consolidated total leverage ratio of the Partnership is in excess of 4.00 to 1.00. The remaining material terms and conditions of the senior secured revolving credit facility, including pricing, maturity and covenants, remained unchanged by the Third Amendment. Prior to the Third Amendment, we had a number of credit facilities. The first was a $100 million revolving credit facility that we entered into in August 2011.

On April 15, 2013, we entered into the Fourth Amendment (the "Fourth Amendment") to the Credit Agreement. The Fourth Amendment amended the Credit Agreement to (i) allow for the transactions contemplated under the Contribution Agreement and the issuance of additional Series A Preferred Units as paid-in-kind distributions, (ii) require the Partnership to repay borrowings under the Credit Agreement with the proceeds of certain asset sales and debt issuances, (iii) increase the maximum allowable consolidated total leverage ratio, including allowing for a higher maximum consolidated total leverage ratio for the seven fiscal quarters starting with the second quarter of 2013 and (iv) reset the applicable interest rates for borrowings based on the consolidated total leverage ratio for each quarter. In addition, the Fourth Amendment provided for a decrease in the aggregate commitments under the Credit Agreement from $200 million to $175 million if, on or prior to September 30, 2013, the Partnership had not received a $12.5 million equity contribution and used that contribution to prepay amounts outstanding under the Credit Agreement. On September 30, 2013, we repaid approximately $12.5 million in outstanding borrowings under the credit agreement in connection with the Equity Restructuring.

On December 17, 2013, we entered into the Fifth Amendment (the "Fifth Amendment") to the Credit Agreement. The Fifth Amendment amends the Credit Agreement to, among other things, reflect the acquisition of Blackwater and its subsidiaries pursuant to the Blackwater Merger Agreement. The Fifth Amendment (i) revised the definition of the term "Consolidated EBITDA," which is used in the calculation of certain financial covenants in the Credit Agreement, to specify how the Consolidated EBITDA of Blackwater would be used to calculate Consolidated EBITDA through the quarter ended on June 30, 2014; (ii) provided that although the Credit Agreement would otherwise require it, Blackwater Maryland, LLC (“Blackwater Maryland”), a subsidiary of Blackwater Holdings, would not be required to deliver any mortgages or deeds of trust on any property of Blackwater Maryland, but that Blackwater Maryland would not grant to any other party any liens on its real property other than liens otherwise permitted by the Credit Agreement; (iii) permitted certain third-party liens to exist on property of Blackwater New Orleans, L.L.C, a subsidiary of Blackwater Holdings; (iv) provided that no more than $20,000,000 of borrowings under the Credit Agreement could be used for the payment of the purchase price in connection with the Blackwater Transaction; and (v) required the Partnership and the American Midstream, LLC to perform certain covenants after the effective date of the Fifth Amendment to ensure that Blackwater Holdings and its subsidiaries become guarantors of the obligations of the Partnership and the American Midstream, LLC under the Credit Agreement and that they secure their obligations and those of the Partnership and the American Midstream, LLC under the Credit Agreement with the assets of Blackwater Holdings and its subsidiaries. In addition, the Fifth Amendment removed certain provisions of the Credit Agreement to provide certain financial and operating information of the Partnership on a monthly basis for any month after 2013 in which the Consolidated Total Leverage Ratio of the Partnership is in excess of 4.00 to 1.00.

As of December 31, 2013 our consolidated total leverage was 3.70, which was in compliance with the consolidated total leverage ratio test in accordance with the leverage covenants as modified in the Fifth Amendment to the credit facility executed on December 17, 2013. As of December 31, 2013, we had approximately $130.7 million of outstanding borrowings under our credit facility and approximately $64.5 million of available borrowing capacity.

We depend on our credit facility for future capital needs and may use it to fund a portion of cash distributions to unitholders, as necessary, depending on the level of our operating cash flow. The Partnership believes that the consummation of the (i) Blackwater Acquisition, (ii) Equity Restructuring, (iii) Offering and (iv) ArcLight Transactions will allow it to maintain compliance with the consolidated total leverage to EBTIDA required under the credit facility.

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 $0.2 million at December 31, 2013.

Cash Flows

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Net cash provided by (used in): | | | |
| Operating activities | $17,223 | $18,348 | $10,432 |
| Investing activities | (28,214) | (62,427) | (41,744) |
| Financing activities | 10,816 | 43,784 | 32,120 |

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012

Operating Activities. Net cash provided by operating activities was $17.2 million for year ended December 31, 2013, compared to $18.3 million for the year ended December 31, 2012. Net cash provided by operating activities for the year ended December 31, 2013, decreased year over year primarily due to (i) $6.6 million and $2.1 million of additional direct operating expenses associated with the contributed High Point System and Blackwater, respectively, and $2.4 million of additional costs associated with our property and casualty insurance; (ii) incremental transaction costs and interest payments of $4.0 million and $4.7 million, respectively; and (iii) a decrease in proceeds received from the settlement of risk management assets and liabilities of $2.2 million; partially offset by (iv) incremental gross margin associated with our High Point System of $19.7 million and our gathering and processing segment of $1.1 million.

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

Investing Activities. Net cash used in investing activities was $28.2 million for the year ended December 31, 2013, compared to $62.4 million for the year ended December 31, 2012. Cash used in investing activities for the year ended December 31, 2013, decreased year over year primarily due to (i) $20.5 million used to fund the expansion of certain strategic systems; (ii) $7.7 million used to fund capital expansion associated with Blackwater; (iii) $2.0 million of funding our restricted cash account; and (iv) $6.1 million used to fund maintenance capital primarily associated improvements at our Bazor Ridge and other systems, as compared to $51.4 million used to fund the acquisition of the Chatom System in July 2012.

Financing Activities. Net cash provided by financing activities was $10.8 million for the year ended December 31, 2013, compared to $43.8 million for the year ended December 31, 2012. Cash provided by financing activities for the year ended December 31, 2013, decreased year over year primarily due to (i) an increase of $2.5 million in net borrowings from our credit facility as result of borrowings to acquire Blackwater offset by contributions from our General Partner; (ii) the issuance of the Series A Units amounting to $14.4 million; and (iii) increased net borrowings from other bank loans of $7.7 million to fund capital expansion associated with Blackwater; offset by (iv) distribution payments of $16.1 million; as compared to higher net borrowings of $62.0 million associated with the acquisition of the Chatom System in July 2012 for the year ended December 31, 2012.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011

Operating Activities. Net cash provided by operating activities was $18.3 million for year ended December 31, 2012, compared to $10.4 million for the year ended December 31, 2011. Net cash provided by operating activities for the year ended December 31, 2012, increased year over year primarily due to (i) incremental gross margin associated with our acquisitions of the Burns Point Plant and the Chatom system of $3.7 million and $5.7 million, respectively; (ii) net positive changes in operating assets and liabilities of $0.9 million due to higher average throughput volumes; (iii) a reduction in premium payments associated with our commodity derivatives of $0.5 million; and (iv) an increase in proceeds received from the settlement of commodity derivatives of $0.5 million.

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

Investing Activities. Net cash used in investing activities was $62.4 million for the year ended December 31, 2012, compared to $41.7 million for the year ended December 31, 2011. Cash used in investing activities for the year ended December 31, 2012, increased year over year primarily due to (i) the purchase of the Chatom system for $51.4 million; (ii) $1.9 million for replacement and capital improvements to assets damaged by Hurricane Isaac during 2012; (iii) $1.7 million for the development of our Madison County system during 2012; and (iv) $1.2 million for turnaround expenditures at the Bazor Ridge and Chatom processing plants.

Financing Activities. Net cash provided by financing activities was $43.8 million for the year ended December 31, 2012, compared to net cash provided by financing activities of $32.1 million for the year ended December 31, 2011. Cash provided by financing activities for the year ended December 31, 2012, increased year over year primarily due to (i) an increase of $52.1 million in net borrowings from our credit facility to fund acquisition and growth opportunities; (ii) a decrease in unit holder distributions of $27.5 million; as compared to $69.1 million in net proceeds from our initial public offering in 2011.

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, 2013, capital expenditures totaled $27.6 million including expansion capital expenditures of $20.5 million, maintenance capital expenditures of $6.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $1.0 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 maintenance capital expenditures of between $5.5 million and $6.5 million and expansion capital expenditures between $55 million and $60 million for the year ending December 31, 2014. Expansion capital expenditures include approximately $30 million to be incurred in 2014 for the construction of gathering pipelines to certain current and future PVA properties.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, which will include debt and common unit issuances, to fund our acquisition and expansion capital expenditures.
We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units and long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

Integrity Management

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

Distributions

On January 22, 2014, we announced that the board of directors of our General Partner declared a quarterly cash distribution of $0.4525 per unit for the fourth quarter ended December 31, 2013, or $1.81 per unit on an annualized basis. The cash distribution was paid on February 14, 2014, to unitholders of record as of the close of business on February 7, 2014, together with the general partner of the Partnership.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2013 (in thousands):

| | Total | Less Than 1 Year | 1 - 3 Years | 3 - 5 Years | More Than 5 Years |
|---|---|---|---|---|---|
| Long-term debt | $130,735 | $— | $— | $130,735 | $— |
| Operating leases and service contract | 6,149 | 959 | 1,826 | 1,394 | 1,970 |
| Asset retirement obligation (“ARO”) | 34,636 | — | 7,867 | — | 26,769 |
| Total | $171,520 | $959 | $9,693 | $132,129 | $28,739 |

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 and Terminals segment.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our 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 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, (i) estimating unbilled revenue and operating and general and administrative costs, (ii) developing fair value assumptions, including estimates of future cash flows and discount rates, (iii) analyzing tangible and intangible assets for possible impairment, (iv) estimating the useful lives of our assets, (v) accounting for income taxes and (vi) 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. We recorded impairments of long-lived assets of $18.2 million for the year ended December 31, 2013. No impairment losses were recognized during the years ended December 31, 2012 and 2011.

Impairment of Goodwill. We evaluate goodwill for impairment annually in the fourth quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.

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, 2013, 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, 2013, we have recorded liabilities of $34.6 million for future asset retirement obligations associated with our pipeline and gathering and processing systems. Related accretion expense has been recorded in Depreciation, amortization and accretion 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.

Revenue Recognition. We recognize revenue when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price is fixed or determinable and (iv) 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. Revenue from firm storage contracts is recognized ratably, which is typically monthly, over the term of the lease. Revenue from throughput fees and ancillary fees are recognized as services are provided to the customer and when the fees are realizable.

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.

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.

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 agreement. These hedging activities rely upon forecasts of our expected operations and financial structure through December 2014. 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 2014 for our commodity hedges. We monitor and review hedging positions regularly.

Recent Accounting Pronouncements

In January 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarifies that ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities, applies to financial instruments or derivative transactions accounted for under ASC 815. The amendments require disclosures to present both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We currently present our net derivative assets and liabilities on our statement of financial position. We have provided additional disclosures regarding the gross amounts of derivative assets and liabilities in Note 6 "Derivatives" in accordance with these new standards updates.

In February 2013, the FASB issued ASU No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("AOCI"), which requires entities to present either in a single note or parenthetically on the face of the financial statements (i) the amount of significant items reclassified from each component of AOCI and (ii) the income statement line items affected by the reclassifications. We adopted this guidance during the first quarter of 2013; it did not have a material impact on our condensed consolidated financial statements as there are currently no items reclassified from AOCI.

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

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.

To minimize the effect of commodity prices and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our general partner. Currently, the commodity derivatives are in the form of swaps and collars. As of December 31, 2013, the aggregate notional volume of our commodity derivatives was 2.9 million gallons.

We enter into commodity contracts with counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of December 31, 2013, we have not been required to post collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

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

During 2013, we entered into additional commodity contracts with existing counterparties to hedge our 2013 and 2014 exposure to commodity prices. As of December 31, 2013, we have hedged approximately 12% of our expected exposure to NGL prices and approximately 14% of our expected exposure to oil prices through the end of 2014.

The table below sets forth certain information regarding the financial instruments used to hedge our commodity price risk as of December 31, 2013 (in thousands):

| Commodity | Instrument | Notional Volumes (a) | Average Price | Period | Fair Value at December 31, 2013 |
|---|---|---|---|---|---|
| NGLs (gals) | Swaps | (2,160,000) | $ 1.09 | Jan 2014 - Dec 2014 | $ (36) |
| Oil (bbls) | Collars (b) | (18,000) | 2.41 | Jan 2014 - June 2014 | (34) |
| | | | | | $ (70) |

(a) Contracted volumes represented as a net short financial position by instrument.
(b) Collars consist of weighted average price for floors and caps of $1.47 and $3.34, respectively.

Interest Rate Risk

During the year ended December 31, 2013, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. During the second quarter of 2013, we entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting the cash flows related to $100 million of our long-term variable rate debt into fixed rate cash flows.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will begin to tighten, resulting in higher interest rates. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $1.3 million for the year ended December 31, 2013.

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

Evaluation of Disclosure Controls and Procedures

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

Our management, including our President and Chief Executive Officer and our Senior Vice President and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) (“Disclosure Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

The management of our General Partner evaluated, with the participation of the Certifying Officers, the effectiveness of our Disclosure Controls and procedures as of the end of the period covered by this report, pursuant to Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2013, the end of the period covered by this report our Disclosure Controls and procedures were effective at a reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f). The Partnership’s internal control over financial reporting was designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2013. This assessment was based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on our assessment, management concluded that as of December 31, 2013 the Partnership’s internal control over financial reporting is effective based on those criteria.

Management has excluded the High Point System which represented 11% of our consolidated net assets and 10% of our consolidated total revenues and the Blackwater Terminals which represented 18% of our consolidated net assets and 3% of our consolidated total revenues from its assessment of internal controls over financial reporting as of December 31, 2013, because they were acquired by the Partnership during 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, that audited the consolidated financial statement included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the internal control over financial reporting as of December 31, 2013, which is included in the consolidated financial statements on page F-1 of this Annual Report.

Changes in Internal Control over Financial Reporting

Management of our General Partner implemented new pipeline transaction management and gas plant allocation software associated with certain significant assets that we believe is a change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2013, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our General Partner's President and Chief Executive Officer and our Senior Vice President and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Annual Report on Form 10-K as Exhibits 31.1 and 31.2. The certifications of our President and Chief Executive Officer and our Senior Vice President 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 do not have directors or officers, which is commonly the case with publicly traded partnerships. 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. High Point Infrastructure Partners and AIM Midstream Holdings own all of the membership interests in our General Partner. Our General Partner has a board of directors ("Board"), and our unitholders are not entitled to elect the directors or directly or indirectly participate in our management or operations. 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 board of directors of our General Partner to designate a Conflicts Committee ("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 the board of directors of our General Partner submits a matter 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 ("Audit Committee"), that complies with the NYSE requirements and a compensation committee of the board of directors ("Compensation Committee"). During 2013, the board of directors of our General Partner introduced a hedge committee to oversee risk management activities.

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 our 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 practices regarding our governance.

All of the senior officers of our General Partner devote a sufficient portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our business; however, they also devote a portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our General Partner, which has separate ongoing business operations.

The non-management members of our General Partner's board of directors meet in executive sessions without management participation at least quarterly. These directors do not constitute a committee of the Board and therefore do not take action at such sessions, although the participating directors may make recommendations for consideration by the full board. Executive sessions shall be chaired by Gerald A. Tywoniuk, the chairman of the Audit Committee

of the board according to the charter of the Audit Committee.
Interested parties may communicate directly with the independent directors by submitting a communication in an envelope marked “Confidential” addressed to the “Independent Members of the Board of Directors” in the care of the Secretary of our General Partner at: American Midstream GP, LLC, 1400 16th Street, Suite 310, Denver, Colorado 80202.

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. Unitholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary, American Midstream GP, LLC, 1400 16th Street, Suite 310, Denver, Colorado 80202. 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.

The independent directors on our General Partner's board are Eileen A. Aptman, Donald R. Kendall Jr. and Gerald A. Tywoniuk. Each of our independent directors, along with Mr. Sutton, serves as members of the Audit Committee, with Mr. Tywoniuk serving as chairman. 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 Mr. Tywoniuk is a financial expert as defined by the NYSE and The Exchange Act and therefore eligible to chair the Audit Committee.

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. Executive officers serve at the discretion of the board of directors of the General Partner and are subject to the terms of their employment agreements, if applicable.

The following table shows information for the executive officers and directors of our General Partner as of December 31, 2013:

| Name | Age | Position with American Midstream GP, LLC |
|---|---|---|
| Stephen W. Bergstrom | 56 | Executive Chairman of the Board, President and Chief Executive Officer |
| Tom L. Brock | 41 | Vice President, Chief Accounting Officer and Corporate Controller |
| Daniel C. Campbell | 43 | Senior Vice President and Chief Financial Officer |
| William B. Mathews | 62 | Secretary, General Counsel and Vice President of Legal Affairs |
| Matthew W. Rowland | 51 | Senior Vice President and Chief Operating Officer |
| Eileen A. Aptman | 46 | Director |
| John F. Erhard | 39 | Director |
| Donald R. Kendall Jr. | 61 | Director |
| Daniel R. Revers | 52 | Director |
| Joseph W. Sutton | 65 | Director |
| Lucius H. Taylor | 40 | Director |
| Gerald A. Tywoniuk | 52 | Director |

Executive officers

Stephen W. Bergstrom was elected as a member of the board of directors of our General Partner in April 2013 and was elected President and Chief Executive Officer in May 2013. He was appointed to the board in connection with his affiliation with ArcLight, which controls our General Partner, and due to his breadth of experience in the energy industry. Mr. Bergstrom has been acting as an exclusive consultant to ArcLight since 2002, assisting ArcLight in connection with its energy investments. Prior to his consultancy with ArcLight, Mr. Bergstrom worked from 1986 to 2002 for Natural Gas Clearinghouse, which became Dynegy, Inc. Mr. Bergstrom acted in various capacities at Dynegy, ultimately acting as its President and Chief Operating Officer. Prior to his time at Dynegy, Mr. Bergstrom acted as a gas supply representative for Northern Natural Gas from 1981 to 1986. Mr. Bergstrom began his career at Transco from 1980-1981. Mr. Bergstrom earned a Bachelor of Science from Iowa State University in 1979. We believe that Mr. Bergstrom’s breadth of experience in the energy industry provide him with the necessary skills to be a member of the board of directors of our General Partner.

Tom L. Brock was appointed Vice President, Chief Accounting Officer and Corporate Controller of the General Partner and the Partnership in November 2013. Mr. Brock had previously served as Vice President and Corporate

Controller of the General Partner and the Partnership beginning in July 2012. Prior to his appointment with the General Partner and the Partnership, Mr. Brock held the position of Director of Trading and Finance with BG Group in Houston, Texas, where he controlled accounting and other functions for its marketing and trading companies beginning in July 2010. Mr. Brock began his career with KPMG LLP, where he spent 13 years holding various positions serving clients in the energy industry. Mr. Brock holds a Bachelor of Accountancy from New Mexico State University and is a CPA licensed in the State of Texas.

Daniel C. Campbell was appointed Senior Vice President and Chief Financial Officer in April 2012. Prior to his appointment with American Midstream, Mr. Campbell served in various leadership roles with MarkWest Energy Partners, LP, from 2006 through 2012, most recently as Vice President of Finance and Treasurer. Mr. Campbell joined MarkWest from TeleTech Holdings, Inc., where he held various senior finance roles from 1997 to 2006 in finance, treasury, strategic planning, and investor relations, including Chief Financial Officer of TeleTech Latin America. Mr. Campbell began his career at Arthur Andersen LLP. He received B.S. and Masters degrees in Accounting from Brigham Young University. Mr. Campbell is a CPA licensed in Colorado.

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.

Matthew W. Rowland was appointed Chief Operating Officer in April 2013. Prior to his appointment with American Midstream, Mr. Rowland was a founder and Managing Director at High Point Energy, LLC (a minority interest owner of HPIP), from 2009 to 2013. Prior to High Point, Mr. Rowland served as Vice President of Asset Optimization for CIMA ENERGY, LTD. from 2003 to 2009. Mr. Rowland began his career with Tenneco/El Paso where he held various operational and commercial roles. Mr. Rowland received a B.S. in Mechanical Engineering from Texas A&M University.

Directors

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. We believe that Ms. Aptman's investment experience and general business knowledge qualifies her to be a member of the board of directors of our General Partner. On January 16, 2014, Ms. Aptman announced her intention to resign from the board of directors. Ms. Aptman has agreed to continue to serve as a director until her replacement is appointed.

John F. Erhard was elected as a member of the board of directors in April 2013 and was appointed to the board in connection with his affiliation with ArcLight, which controls our General Partner. Mr. Erhard, a Partner at ArcLight, joined the firm in 2001 and has 14 years of energy finance and private equity experience. Prior to joining ArcLight, he was an Associate at Blue Chip Venture Company, a venture capital firm focused on the information technology sector. Mr. Erhard began his career at Schroders, where he focused on mergers and acquisitions. Mr. Erhard earned a Bachelor of Arts in Economics from Princeton University and a Juris Doctor from Harvard Law School. Mr. Erhard previously served on the Board of Directors of Patriot Coal. In addition, Mr. Erhard has experience in the MLP sector having served on the board of directors of Buckeye GP Holdings, the publicly traded General Partner of Buckeye Partners (NYSE: BPL). We believe that Mr. Erhard’s 14 years of energy finance and private equity experience provide him with the necessary skills to be a member of the board of directors of our General Partner.

Donald R. Kendall, Jr. was elected a member of the board of directors of our General Partner in July 2013. Mr. Kendall serves as an independent director and as a member of the Audit Committee. Mr. Kendall is currently Managing Director and Chief Executive Officer of Kenmont Capital Partners, LP, an investment management firm based in Houston specializing in alternative investments and private equity. Prior to joining Kenmont, Mr. Kendall was a Portfolio Manager for Carlson Capital, L.P., President of Cogen Technologies Capital Company, L.P., Chairman and Chief Executive Officer of Palmetto Partners, Ltd., and a Managing Director in the project finance and leasing group at Credit Suisse First Boston. Mr. Kendall also serves as a director of SolarCity, Stream Energy, and

Tangent Energy Solutions. In addition, Mr. Kendall serves in various capacities at not-for-profit organizations, including The Jane Goodall Institute, The Houston Zoo Conservation Committee, and Earthwatch International. He also is on the Board of Overseers of the Amos Tuck School of Business Administration at Dartmouth College. Mr. Kendall received a B.A. degree from Hamilton College and an M.B.A. with high honors from The Amos Tuck School of Business Administration. He was a Tuck Scholar and a recipient of the W. M. Bollenbach, Jr. Fellowship. We believe that Mr. Kendall's investment experience and general business knowledge qualifies him to be a member of the board of directors of our General Partner.

Daniel R. Revers was elected as a member of the board of directors in April 2013 and was appointed to the board in connection with his affiliation with ArcLight, which controls our General Partner. Mr. Revers is Managing Partner of and a co-founder of ArcLight and has 24 years of energy finance and private equity experience. Mr. Revers manages the Boston office of ArcLight and is responsible for overall investment, asset management, strategic planning, and operations of ArcLight and its funds. Prior to forming ArcLight in 2000, Mr. Revers was a Managing Director in the Corporate Finance Group at John Hancock Financial

Services (“John Hancock”), where he was responsible for the origination, execution, and management of a $6 billion portfolio consisting of debt, equity, and mezzanine investments in the energy industry. Prior to joining John Hancock in 1995, Mr. Revers held various financial positions at Wheelabrator Technologies, Inc., where he specialized in the development, acquisition, and financing of domestic and international power and energy projects. Mr. Revers serves in various capacities for a number of not-for-profit organizations, currently serving on the Board of Overseers at the Amos Tuck School of Business Administration, and the Board of Directors of The Citizen Schools. Mr. Revers earned a Bachelor of Arts in Economics from Lafayette College and a Master of Business Administration from the Amos Tuck School of Business Administration at Dartmouth College. We believe that Mr. Revers’s over 24 years of energy finance and private equity experience provide him with the necessary skills to be a member of the board of directors of our General Partner.

Joseph W. Sutton was elected as a member of the board of directors in May 2013 and was appointed to the board in connection with his affiliation with ArcLight. Since 2000, Mr. Sutton has been the manager of Sutton Ventures Group, LLC, an energy investment firm that he founded. In 2007, he founded and has since led Consolidated Asset Management Services, or CAMS, which provides asset management, operations and maintenance, information technology, budgeting, contract management and development services to power plant ventures, oil and gas companies, renewable energy companies and other energy businesses. From 1992 to November 2000, Mr. Sutton worked for Enron Corporation, an energy company, where he most recently served as vice chairman and as chief executive officer of Enron International. We believe that Mr. Sutton’s over 20 years of energy finance experience provide him with the necessary skills to be a member of the board of directors of our General Partner.

Lucius H. Taylor was elected as a member of the board of directors in April 2013 and was appointed to the board in connection with his affiliation with ArcLight, which controls our General Partner. Mr. Taylor joined ArcLight in 2007. He has 15 years of experience in energy and natural resource finance and engineering. Prior to joining ArcLight, Mr. Taylor was a Vice President in the Energy and Natural Resource Group at FBR Capital Markets where he focused on raising public and private capital for companies in the power and energy sectors. Mr. Taylor began his career as a geologist and project manager at CH2M HILL, Inc., a global engineering, construction, and operations firm. Mr. Taylor earned a Bachelor of Arts in Geology from Colorado College, a Master of Science in Hydrogeology from the University of Nevada, and a Master of Business Administration from the Wharton School at the University of Pennsylvania. We believe that Mr. Taylor’s over 15 years of energy finance and private equity experience 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. From May 2010 to the present, Mr. Tywoniuk has provided interim and project CFO services. He also currently serves as a director and audit committee chairperson on the board of the General Partner of Oxford Resource Partners, LP (NYSE:OXF). From June 2008 through August 2013, Mr. Tywoniuk served Pacific Energy Resources Ltd. in various senior roles (Senior Vice President, Finance beginning June 2008, Chief Financial Officer beginning August 2008, acting Chief Executive Officer and CFO beginning September 2009, Plan Representative beginning December 2010). He held these positions as an employee until May 2010 and as a consultant on a part-time basis until August 2013. Pacific Energy Resources Ltd. was an oil and gas acquisition, exploitation and development company. Mr. Tywoniuk joined the company 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 in August 2013 completed its 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. Mr. Tywoniuk has 32 years of experience in accounting and finance, including 12 years as the Chief Financial Officer of three public companies and four 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.”

Family Relationships

There are no family relationships among any of the Partnership’s directors and executive officers.

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% 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.

Based solely upon a review of Forms 3 and 4, and amendments thereto, during fiscal 2013, the Partnership knows of no director, officer, or beneficial owner of more than 10% of any class of equity securities of the Company registered pursuant to Section 12 of the Exchange Act that failed to file timely any reports required to be furnished pursuant to Section 16(a) of the Exchange Act, except, as follows:

i. On September 3, 2013, Donald R. Kendall, Jr. was one day late filing a Form 4.
ii. Marty W. Patterson, former SVP of Commercial Services had a total of three untimely filings of Form 4. On September 3, 2013, he was twenty-five days late; on August 23, 2013, he was forty-seven days late; and on April 26, 2013, he was five days late.
iii. On August 23, 2013, Eileen A. Aptman was eight days late filing a Form 4.
iv. On August 23, 2013, John J. Connor II, former SVP of Operations and Engineering was fifteen days late filing a Form 4.
v. On August 23, 2013, Donald H. Anderson was eight days late filing a Form 4.
vi. On August 23, 2013, Gerald A. Tywoniuk was eight days late filing a Form 4.
vii. On April 26, 2013, Brian F. Bierbach was five days late filing a Form 4.
viii. On April 26, 2013, Daniel C. Campbell was five days late filing a Form 4.

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 year ended December 31, 2013:

- Stephen W. Bergstrom, President and Chief Executive Officer;
- Brian F. Bierbach, former President and Chief Executive Officer;
- Daniel C. Campbell, Senior Vice President and Chief Financial Officer;
- Matthew W. Rowland, Senior Vice President and Chief Operating Officer; and
- Michael D. Suder, Chief Executive Officer of Blackwater; and
- William B. Mathews, Secretary, Vice President of Legal Affairs and General Counsel.

Our compensation program is designed to recognize key managers are critical to our Partnership’s profitability and growth. We utilize compensation to attract and retain management talent and to motivate key employees to focus consistently on growth and value creation. In addition, our compensation program aligns incentives for management and shareholder, focusing on long-term value creation rather than short-term gain. To do this, our compensation program for key managers is made up of the following main components: (i) base salary, designed to compensate our executives for work performed during the fiscal year; (ii) short-term incentive programs, designed to reward our executives for our yearly performance and for their individual performances during the fiscal year; and (iii) equity-based awards, meant to align our executives 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 three years ended December 31, 2013.

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 2013, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2014 and 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, with respect to our results for the prior year, (ii) reviewing and assessing the personal performance of the executive officers and other key managers for the preceding year and (iii) determining the amount of the bonus pool to be paid to our executives and other key managers for a given year after taking into account the target bonus amounts established for those executives and other key managers 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 and key managers 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 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 as well as the amounts allocated to the short-term incentive plan and LTIP compensation pools.

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 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.

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 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 resulted from the exercise of judgment based on all reasonably available information and, to that extent, were discretionary. The current and prior compensation of each executive and key manager 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 executive officers and key individuals with the skills necessary to execute our business strategy and develop, grow and manage our business.

The Compensation Committee has also utilized benchmarking compensation levels across a range of publicly traded Master Limited Partnerships operating in the midstream market to inform specific award levels for Named Executive Officers and key managers. 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, but not be limited to, 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 Energy Corporation, Approach Resources, Inc., PetroQuest Energy Inc. and Rex Energy Corporation.

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. Increases or adjustments may be made based on both company and individual performance or such factors as the Compensation Committee may determine. | Align performance to our objectives that drive our business and reward executive officers for achieving our yearly performance objectives and for their individual contributions to these objectives 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, and 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, have not been granted as part of the 2014 LTIP, but future awards may be eligible for DERs at the discretion of the Compensation Committee and approval by the Board. | 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. |
| 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 | Provide our executive officers and other employees with the opportunity to save for their future retirement. |

| | | |
|---|---|---|
| | to the plan. For 2013, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% of the employee's eligible compensation. | |
| 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. |

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 development and execution of strategic plans, leading 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 salary decisions will continue to focus on the above considerations and will also take into account relevant market data, including the market data and peer group data.

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.

The Compensation Committee approved the following base salaries for 2013 for the named executive officers as provided in the table below.

| Name | Base Salary at the end of 2013 |
|---|---|
| Stephen W. Bergstrom (a) | $1 |
| Brian F. Bierbach (b) | — |
| Daniel C. Campbell | 235,000 |
| Matthew W. Rowland | 285,000 |
| Michael D. Suder | 300,000 |
| William B. Mathews | 215,000 |

(a) Mr. Bergstrom was also compensated in 2013 through a consulting agreement with ArcLight that has been in effect for more than 10 years. Accordingly, during 2013 Mr. Bergstrom allocated time to ArcLight on matters not related to American Midstream, as well as to matters related to the General Partner of American Midstream and HPIP, the majority owner of the General Partner, none of which is considered compensation for services rendered in conjunction with his role as President and CEO of American Midstream.

(b) Mr. Bierbach was the former President and Chief Executive Officer of our General Partner until May 2013 when he was appointed to Senior Vice President of Business Development until he resigned in November 2013.

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 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 and are determined at the discretion of the Compensation Committee with input from the CEO.

While target bonuses for our executive officers who have entered into employment agreements have been initially set at dollar amounts that are 75% 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, 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 2013 for all of the executive officers, which are specified in their employment agreements, are set forth in the table below. Please refer to "—Employment Agreements with Named Executive Officers" below for a description of the employment agreements.

The Board and the Compensation Committee believe that this approach to assessing performance results in a more comprehensive evaluation for compensation decisions. In 2013, the Compensation Committee recognized the following factors in making discretionary annual bonus recommendations and determinations:

- a subjective company performance evaluation based on company-wide financial performance including actual EBITDA versus budgeted EBITDA to assess company performance and adjusted as needed for new acquisitions and major capital programs in 2013;
- a subjective individual performance evaluation for executive officers and other factors the CEO may deem relevant; 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 believes 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 as compared to operating budget 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 determines to award the base salary and incentive bonus amounts set forth in the table below to our named executive officers for performance in 2013.

| Name | 2013 Base Salary | 2013 Target Bonus | 2013 Bonus Earned |
|---|---|---|---|
| Stephen W. Bergstrom | $1 | $— | $— |
| Brian F. Bierbach (a) | 275,000 | N/A | N/A |
| Daniel C. Campbell | 235,000 | 176,250 | 382,000 |
| Matthew W. Rowland | 285,000 | 213,750 | 250,000 |
| Michael D. Suder | 300,000 | 162,500 | 181,250 |
| William B. Mathews | 215,000 | 161,250 | 150,000 |

(a) Mr. Bierbach was the former President and Chief Executive Officer of our General Partner until May 2013 when he was appointed to Senior Vice President of Business Development until he resigned in November 2013.

Beginning in 2013, the Compensation Committee expected that it would determine 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;
- unitholder total return for the prior fiscal year; and
- competitive compensation data of executive officers.

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.

Equity-Based Awards

Design. The LTIP was adopted in 2009 in connection with our formation and most recently amended and restated in 2012. 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. As part of this initial formation, we granted phantom units with associated DERs to provide long-term incentives to our named executive officers. DERs enabled 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. Units awarded as part of the 2014 LTIP will not be eligible for DERs. Future awards may be eligible for DERs. The CEO may recommend to the Compensation Committee the distribution of DERs associated with subsequent awards but payout of DERs must be approved by the Board.

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 unitholder value, 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 long-term 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.

Equity-Based Award Policies. Prior to 2011, equity-based awards were granted by the Compensation Committee in connection with our formation. In 2013, Messrs. Bierbach, Campbell, Connor, Mathews and Patterson received units in connection with the acquisition by High Point Infrastructure Partners, LLC ("HPIP"), an affiliate of ArcLight Capital Partners, LLC, of an interest in our General Partner, effective April 15, 2013. Mr. Rowland received an award upon his employment in April 2013.

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 2013, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% 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 2013 and 2012, 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 2014, 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. Campbell, Rowland, and Suder, which 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."

Summary Compensation Table for the Three Years ended December 31, 2013

The following table sets forth certain information with respect to the compensation paid to the named executive officers for the three years ended December 31, 2013.

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| | Year | Salary | Bonus | Unit Awards (a) | All Other Compensation | Total Compensation |
|---|---|---|---|---|---|---|
| Stephen W. Bergstrom Executive Chairman, President and Chief Executive Officer | 2013 | $1 | $— | $— | $— | $1 |
| | 2012 | — | — | — | — | — |
| | 2011 | | | | | |
| Brian F. Bierbach Former President and Chief Executive Officer | 2013 | 290,039 | — | 165,000 | — | 455,039 |
| | 2012 | 275,000 | — | — | — | 275,000 |
| | 2011 | 251,615 | 220,000 | — | 478,870 | 950,485 |
| Daniel C. Campbell Senior Vice President and Chief Financial Officer | 2013 | 235,000 | 132,000 | 213,230 | — | 580,230 |
| | 2012 | 162,692 | — | 214,000 | — | 376,692 |
| | 2011 | — | — | — | — | — |
| Matthew W. Rowland Senior Vice President and Chief Operating Officer | 2013 | 122,577 | — | 527,000 | — | 649,577 |
| | 2012 | — | — | — | — | — |
| | 2011 | — | — | — | — | — |
| Michael D. Suder (b) Chief Executive Officer of Blackwater | 2013 | 408,750 | 181,250 | — | — | 590,000 |
| | 2012 | — | — | — | — | — |
| | 2011 | — | — | — | — | — |
| William B. Mathews Vice President Legal Affairs, General Counsel and Secretary | 2013 | 215,750 | — | 214,500 | — | 430,250 |
| | 2012 | 215,000 | — | — | — | 215,000 |
| | 2011 | 198,361 | 91,000 | — | 93,561 | 382,922 |

(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 awards granted in each of the three years ended December 31, 2013, 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 15 "Long-term Incentive Plan" to our audited consolidated financial statements included in this Form 10-K.

(b) American Midstream Blackwater, LLC become a wholly owned subsidiary of American Midstream, LLC effective December 17, 2013.

Grants of Plan-Based Awards for 2013

| Name | Grant Date | Estimated Future Payouts Under Equity Incentive Plan Awards Threshold # | Target # | Maximum # | Grant Date Fair Value of Unit Awards ($) |
|---|---|---|---|---|---|
| Stephen W. Bergstrom | — | — | — | — | $— |
| Brian F. Bierbach (a) | 04/14/13 | — | — | 10,000 | 165,000 |

| | | | | | |
|---|---|---|---|---|---|
| Daniel C. Campbell | 04/14/13 | — | — | 12,923 | 213,230 |
| Matthew W. Rowland | 08/22/13 | — | — | 25,000 | 527,000 |
| William B. Mathews | 04/14/13 | — | — | 13,000 | 214,500 |
| Michael D. Suder | — | — | — | — | — |

(a) Mr. Bierbach was the former President and Chief Executive Officer of our General Partner until May 2013 when he was appointed to Senior Vice President of Business Development until he resigned in November 2013.

Employment Agreements with Named Executive Officers

Our General Partner has entered into employment agreements with certain of our named executive officers. 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 our General Partner). The agreements provide that the executive will be provided with the opportunity to earn an annual cash bonus, a certain percent of which will be conditioned and determined on the attainment of personal performance goals and the balance 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 may also be eligible to receive awards under the LTIP as determined by the Compensation Committee.

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 employment agreements.

Outstanding Equity-Based Awards at December 31, 2013

The following table provides information regarding outstanding split adjusted equity-based awards held by the named executive officers as of December 31, 2013. All such equity-based awards consist of phantom units granted under the LTIP.

| | Unit Awards | |
|---|---|---|
| Name | Number of Phantom Units that Have Not Vested | Market Value of Phantom Units that Have Not Vested (h) |
| Stephen W. Bergstrom | — | $ — |
| Brian F. Bierbach (a) | — | — |
| Daniel C. Campbell | 6,461 (b) | 174,964 |
| | 5,000 (c) | 135,400 |
| Matthew W. Rowland | 25,000 (d) | 677,000 |
| William B. Mathews | 6,500 (f) | 176,020 |
| | 3,130 (g) | 84,760 |
| Michael D. Suder | — | — |

(a) Mr. Bierbach was the former President and Chief Executive Officer of our General Partner until May 2013 when he was appointed to Senior Vice President of Business Development until he resigned in November 2013.

(b) This award vested 50% upon its April 14, 2013, grant date and will vest 25% on each of the two anniversaries thereafter. The awards to Mr. Campbell were granted on April 12, 2012 and April 14, 2013, vesting 50% on each of the first two anniversaries of the date of grant for the first grant and 50% immediate vesting and 25% on each of the first two anniversaries of the date of grant for the second grant.

(c) This award vested 50% the first anniversary of its April 12, 2012, grant date and 50% on the first anniversary thereafter.

(d) This award vests 33% on each of the first three anniversaries of its August 22, 2013, grant date.

(e) This award vested 50% upon its April 14, 2013, grant date and will vest 25% on each of the two anniversaries thereafter.

(f) This award vested 50% upon its April 14, 2013, grant date and will vest 25% on each of the two anniversaries thereafter.

(g) The market value of phantom units that had not vested as of December 31, 2013, is calculated based on the fair market value of our common units as of December 31, 2013, which was $27.08 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 2013

The following table shows the split adjusted phantom unit awards that vested during 2013.

| Name | 2013 Number of Units Acquired on Vesting | Fair Market Value per Unit Upon Vesting | Value Realized on Vesting (b) |
|---|---|---|---|
| Stephen W. Bergstrom | — | $— | $— |
| Brian F. Bierbach (a) | | | |
| 04/14/2013 vest | 5,000 | $16.50 | $82,500 |
| 11/02/2013 vest | 18,775 | $23.90 | $448,723 |
| Daniel C. Campbell | | | |
| 04/14/2013 vest | 6,462 | $16.50 | $106,623 |
| 05/01/2013 vest | 5,000 | $18.65 | $93,250 |
| Matthew W. Rowland | — | — | — |
| William B. Mathews | | | |
| 04/14/2013 vest | 6,500 | $16.50 | $107,250 |
| 03/02/2013 vest | 3,129 | $16.91 | $52,911 |
| Michael D. Suder | — | — | — |

(a) Mr. Bierbach was the former President and Chief Executive Officer of our General Partner until May 2013 when he was appointed to Senior Vice President of Business Development until he resigned in November 2013.

(b) 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 two LTIPs for employees, consultants and directors of our General Partner and affiliates who perform services for us. The plans provide 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 LTIPs. Currently, outstanding awards are phantom units without DERs.

As of December 31, 2013, 75,528 unvested phantom units were outstanding under our LTIPs. A phantom unit is a notional unit granted under the LTIPs 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 LTIPs may not exceed 920,193 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 LTIPs. 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 LTIPs with respect to other awards. There is no limitation on the number of awards that may be granted under the LTIPs and paid in cash. The LTIPs provide that they are to be administered by the Board, provided that the Board may delegate authority to administer the LTIPs to a committee of non-employee directors. As of March 7, 2014, there are 854,637 units available for future grant awards.

The LTIPs 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. Each 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.

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, 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 $1.3 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 our unitholders sell or exchange their interests 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, 2013:

| Name | Benefit Type | Death or Disability(a) | Termination Without Cause, or Upon Expiration(b) | Resignation for Good Reason | Certain Changes of Control (a)(c) |
|---|---|---|---|---|---|
| Stephen W. Bergstrom | N/A | N/A | N/A | N/A | N/A |
| Brian F. Bierbach | N/A | N/A | N/A | N/A | N/A |
| Daniel C. Campbell | Severance payment per employment agreement | None | $411,250 | $411,250 | 411,250 |
| | Accelerated vesting of phantom unit awards per award agreement | $310,300 | None | None | $310,300 |
| Matthew W. Rowland | Severance payment per employment agreement | None | $275,000 | $275,000 | None |
| | Accelerated vesting of phantom unit awards per award agreement | $677,000 | None | None | $677,000 |
| William B. Mathews | Accelerated vesting of phantom unit awards per award agreement | $260,780 | N/A | N/A | N/A |
| Michael D. Suder | Severance payment per employment agreement | None | $300,000 | $300,000 | None |
| | Accelerated vesting of phantom unit awards per award agreement | N/A | None | None | N/A |

(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 $27.08, multiplied by the number of phantom units that would vest as of December 31, 2013.

(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 non-competition 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

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the Board is comprised of Messrs. Bergstrom and Erhard and Ms. Aptman. The Compensation Committee makes compensation decisions regarding the executive officers of our General Partner. With the exception of Mr. Bergstrom, none of the members of the Compensation Committee is or has been one of our officers or employees, and none of our executive officers served during 2013 on a board of directors or compensation committee of another entity which has employed any of the members of our board of directors or compensation committee.

Director Fees

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 unit grant;
- where applicable, a variable fee for service rendered as member of the Conflicts Committee to the board of directors; 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.

Generally, non-employee directors listed in the table below are 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.

Director Compensation Table for 2013

The following table sets forth the compensation paid to our non-employee directors for the year ended December 31, 2013, as described above. The compensation paid in 2013 to Messrs. Bergstrom and Bierbach as an executive officer is set forth in the Summary Compensation Table above. Messrs. Bergstrom and Bierbach did not receive any additional compensation related to their service as a director.

| | Fees Earned or Paid in Cash | Unit Awards (a) | All Other Compensation | Total Compensation |
|---|---|---|---|---|
| Donald H. Anderson | $79,306 | $40,548 | $— | $119,854 |
| Eileen A. Aptman | 84,056 | 38,354 | — | 122,410 |
| Edward O. Diffendal (b) | — | — | — | — |
| John F. Erhard | — | — | — | — |
| Robert H. Hellman Jr. (b) | — | — | — | — |
| Donald R. Kendall Jr. | 36,667 | 13,671 | — | 50,338 |
| L. Kent Moore (b) | 23,973 | 103,274 | — | 127,247 |
| Daniel R. Revers | — | — | — | |