American Midstream Partners, LP
Form 10-K
March 07, 2016

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, 2015

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 (§229.405 of this chapter) 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. (Check one):

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2015, was $354,233,679. The aggregate market value was computed by reference to the closing price of the registrant's common units on the New York Stock Exchange on June 30, 2015.

There were 30,889,659 common units and 9,499,370 Series A Units of American Midstream Partners, LP outstanding as of March 4, 2016. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

Documents Incorporated by Reference

None.

TABLE OF CONTENTS

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 words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.
These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" in this Annual Report on Form 10-K (the "Annual Report") as well as the following risks and uncertainties:

- our ability to generate sufficient cash from operations to pay distributions to unitholders;
- our ability to maintain compliance with financial covenants and ratios in our credit facility;
- the timing and extent of changes in natural gas, crude oil, NGLs and other commodity prices, interest rates and demand for our services;
- the level and success of natural gas and crude oil drilling around our assets and our success in connecting natural gas and crude oil supplies to our gathering and processing systems;
- our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions;
- our dependence on a relatively small number of customers for a significant portion of our gross margin;
- 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;
- our ability to successfully balance our purchases and sales of natural gas;
- the demand for NGL products by the petrochemical, refining or other industries;
- severe 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;
- the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects;
- our management's history and experience with certain aspects of our business and our ability to hire as well as retain qualified personnel to execute our business strategy;
- our ability to remediate any material weakness in internal control over financial reporting;
- 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;
- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- the amount of collateral required to be posted from time to time in our transactions; and
-

our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks.

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. Statements in this Annual Report speak as of the date of this report. Except as may be required by applicable securities laws, we undertake no obligation to publicly update or advise investors of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

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

| | |
|---|---|
| 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 natural 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. |
| GAAP | Generally Accepted Accounting Principles in the United States of America |
| Gal | Gallons. |
| Mgal/d | Million gallons per day. |
| 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. |
| MMcf/d | Million cubic feet per day. |
| 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. References in this Annual Report to our "General Partner" refer to American Midstream GP, LLC.

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, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products, all through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three marine terminal sites, three interstate pipelines, five intrastate pipelines and one crude oil pipeline. We also own a 66.7% non-operated interest in Main Pass Oil Gathering Company ("MPOG"), a crude oil gathering and processing system; a 50% undivided, non-operated interest in the Burns Point Plant, a natural gas processing plant; a 46% non-operated interest in Mesquite, an off-spec condensate fractionation project; and a 12.9% non-operated indirect interest in Delta House, a floating production system platform and related pipeline infrastructure. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas, and the Gulf of Mexico, provide critical infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate more than 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.8 million barrels of storage capacity across three marine terminal sites.

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, processing, transporting and treating natural gas and crude oil. 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.

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines.

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

Recent Developments

Delta House Investment

On September 18, 2015, the Partnership acquired a 26.3% non-operated interest in Pinto Offshore Holdings, LLC ("Pinto") (the "Delta House Investment"), an entity that owns a non-operated interest in (i) approximately 49% of the limited liability company interests of Delta House FPS LLC and (ii) approximately 49% of the limited liability company interests of Delta House Oil and Gas Lateral LLC, which respectively own the Delta House floating production system and related pipeline infrastructure ("Delta House"). We acquired our interest in Pinto in exchange for $162.0 million in cash. The Partnership funded the purchase price with the net proceeds of its public offering of 7.5 million common units which closed on September 15, 2015, and with borrowings under the Partnership's Amended and Restated Credit Agreement, as amended by the First Amendment and Incremental Commitment

Agreement, dated as of September 14, 2014 (as amended, the "Credit Agreement").

Delta House is a floating production platform system with associated crude oil and natural gas export pipelines, located in the Mississippi Canyon region of the deepwater Gulf of Mexico with nameplate processing capacity of 80,000 barrels of crude oil per day (Bbl/d) and 200 million cubic feet of natural gas per day (MMcf/d), and peak processing capacity of 100,000 Bbl/d of crude oil and 240 MMcf/d of gas. Cash flows for Delta House are supported by a 100% fee-based tiered tariff structure with ship-or-pay components. Delta House was developed by ArcLight Capital Partners, LLC ("ArcLight") and LLOG Exploration Offshore, LLC ("LLOG Exploration"), a leading private deepwater exploration company in the Gulf of Mexico, as well as a consortium of exploration companies, and commenced operations in April 2015. LLOG Exploration operates Delta House.

Series A-2 Convertible Preferred Units

On March 30, 2015 and June 30, 2015, we entered into two Unit Purchase Agreements with Magnolia Infrastructure Partners, LLC ("Magnolia"), which is an affiliate of High Point Infrastructure Partners, LLC ("HPIP") pursuant to which the Partnership issued, in separate private placements, Series A-2 Convertible Preferred Units ("Series A-2 Units") for approximately $45.0 million in gross proceeds. The Series A-2 Units will participate in distributions of the Partnership along with common units in a manner identical to the existing Series A Convertible Preferred Units (such previously existing Series A Units are referred to as the "Series A-1 Units" and, together with the Series A-2 Units, the "Series A Units"), with such distributions being made in cash or with paid-in-kind Series A Units at the election of the Board of Directors of our General Partner. The Board of Directors of our General Partner has, to date, elected to pay distributions on Series A Units using paid-in-kind Series A Units, which began with the distribution for the three months ended June 30, 2014 and will continue through the distribution for the quarter ended March 31, 2016.

Partnership Agreement Amendment

On July 27, 2015, we entered into the Fifth Amendment (the “Fifth Amendment”) to the Fourth Amended and Restated Agreement of Limited Partnership ("the Partnership Agreement"). The Fifth Amendment grants us the right (the “Call Right”) to require the holders of the Series A-2 Units (the “Series A-2 Holders”) to sell, assign and transfer all or a portion of the then outstanding Series A-2 Units to us for a purchase price of $17.50 per Series A-2 Unit (subject to appropriate adjustments). We may exercise the Call Right at any time, in connection with our acquisition of assets or equity from ArcLight Energy Partners Fund V, L.P., or one of its affiliates, for a purchase price in excess of $100 million. We may not exercise the Call Right with respect to any Series A-2 Units that a Series A-2 Holder has elected to convert into common units on or prior to the date we have provided notice of our intent to exercise the Call Right, and may not exercise the Call Right if doing so would result in a default under any of our financing agreements or obligations.

Market Conditions

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.43 per barrel to a low of $26.21 per barrel from January 1, 2015 through March 1, 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.23 per MMBtu to a low of $1.71 per MMBtu from January 1, 2015 through March 1, 2016. We are unable to predict future movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. For the year ended December 31, 2015, net loss attributable to the Partnership was $127.5 million, primarily as a result of impairments of goodwill of $118.6 million, compared to net loss attributable to the Partnership of $98.0 million, primarily as a result of impairments of property, plant and equipment, for the year ended December 31, 2014. If commodity prices remain depressed or continue to trend lower as they did in 2015 and early 2016, this could lead to reduced profitability and may impact our liquidity and compliance with the financial covenants in our Credit Agreement. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets, as well as the reduction or elimination of distributions to our unitholders.

Business Strategies

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

Continue Our Commitment to Safe and Environmentally Sound Operations. The safety of our employees and the communities in which we operate is our highest priority. We believe it is critical to safely handle natural gas, crude oil 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.

Pursue Strategic and Accretive Acquisitions, Including Acquisitions from ArcLight and Its Affiliates in Drop Down Transactions. We plan to pursue accretive acquisitions of energy infrastructure assets, including in drop-down transactions from ArcLight who control our General Partner, and its affiliates, that are complementary to our existing asset base or that provide attractive returns in new operating regions or business lines. We plan to 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 also plan to 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.

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 we believe provide attractive returns. 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 intend to develop assets in our current lines of business, but may pursue opportunities in new but related business lines as well.

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, crude oil and specialty chemicals to our systems and terminals 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 the 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 often seeking to mitigate direct commodity price exposure by using hedging activities. For the years ended December 31, 2015, 2014, and 2013, $105.8 million, $76.6 million, and $48.7 million, or 85.8%, 74.4%, and 65.1% 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. The GAAP measure most comparable to gross margin is net income (loss) attributable to the Partnership. Those contracts, together with our percent-of-proceeds contracts, generated relatively stable cash flows. Due to declining commodity prices, we had not entered into commodity hedge contracts to hedge production in 2016 and beyond as of December 31, 2015.

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 develop of new asset platforms and attractive organic growth projects and acquisitions.

Competitive Strengths

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

Relationship with ArcLight. ArcLight controls HPIP, the majority owner of our General Partner, and has a proven track record of investments across the energy industry. ArcLight bases its investments on fundamental asset values and defined growth strategies with a focus on investing in 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 and the Gulf of Mexico, 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, crude oil and specialty chemical supplies and to capture new customers who are underserved by our competitors. Upon the stabilization of the commodities market, we expect drilling activity to recommence or continue on and around the majority of our assets, and we believe that our assets are strategically positioned to capitalize on this drilling activity, increased demand for midstream services and growing commodity consumption in the shale plays of the Bakken, Eagle Ford and Permian as well as East Texas, 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, which often causes our systems to be more attractive than those of our competitors.

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 attractive to our competitors. Given the size of our business, these opportunities may have a larger financial impact on us than they would on our competitors and may provide us with material growth opportunities. The benefits of our size and flexibility apply not only to the opportunities around our current assets but also to opportunities to develop new asset platforms as well, which allows us to pursue the development of new systems that may positively impact our company.

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.

Experienced Management and Operating Teams. Our executive management team has an average of approximately 25 years of experience in the midstream energy industry. The team possesses a comprehensive skill set to support our business and enhance unitholder value through asset optimization, accretive development projects and acquisitions. In addition, our field supervisory team has operated our assets for an average of more than 25 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 Second Amended and Restated Long-Term Incentive Plan or Third Amended and Restated Long-Term Incentive Plan (as applicable, the "Long-Term Incentive Plan" or "LTIP").

Our Assets

We own and operate twelve gathering systems, five processing facilities, three fractionation facilities, three marine terminal sites, three interstate pipelines, five intrastate pipelines and one crude oil pipeline. We also own a 66.7% non-operated interest in MPOG, a crude oil gathering and processing system; a 50% undivided, non-operated interest in the Burns Point Plant, a natural gas processing plant; a 46% non-operated interest in Mesquite, an off-spec condensate fractionation project; and a 12.9% non-operated indirect interest in Delta House, a floating production system platform and related pipeline infrastructure. Our primary assets are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas and the offshore Gulf of Mexico. We organize our operations into three business segments: i) Gathering and Processing; ii) Transmission; and iii) Terminals.

Gathering and Processing Segment

General

Our Gathering and Processing segment consists of midstream natural gas systems that provide the following services to our customers:

- gathering;
- compression;
- treating;
- processing;
- fractionating;
- transportation; and
- sales of natural gas, crude oil, NGLs and condensate.

Our Gathering and Processing assets are located in Alabama, Louisiana, Mississippi, North Dakota and Texas and in shallow state and federal waters in the Gulf of Mexico off the coast of Louisiana and are positioned in areas with opportunities for organic growth. We continually seek new sources of raw natural gas and crude oil supply to maintain and increase the throughput volume on our gathering systems and through our processing plants.

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. For the year ended December 31, 2015, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 77.3% and 22.7%, respectively, of our segment gross margin for the Gathering and Processing segment. For the year ended December 31, 2014, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 48.3% and 51.7%, respectively, of our segment gross margin for the Gathering and Processing segment.

The following table provides information regarding our Gathering and Processing segment assets as of December 31, 2015, and for the years ended December 31, 2015 and 2014.

| | Approximate Gas Gathering System (Miles) | Approximate Design Capacity (MMcf/d) | Compression (Horsepower) | Number of Plants and Fractionators | Approximate Average Throughput (MMcf/d) Years Ended December 31, | |
|---|---|---|---|---|---|---|
| | | | | | 2015 | 2014 |
| Gathering and Processing | | | | | | |
| Lavaca (a) | 203 | 218 | 32,000 | — | 119.1 | 65.0 |
| Magnolia | 116 | 120 | 3,328 | — | 27.1 | 21.7 |
| Longview (b) | 620 | 50 | 23,880 | 3 | 17.2 | 4.7 |
| Chapel Hill (b) | 90 | 20 | 2,540 | 2 | 14.6 | 4.1 |
| Yellow Rose (b) | 47 | 40 | 3,256 | 1 | 4.2 | 1.3 |
| Bakken (c) | 43 | 40 | — | — | — | — |
| Chatom (d) | 24 | 25 | 3,456 | 2 | 5.9 | 6.4 |
| Bazor Ridge | 169 | 22 | 8,615 | 1 | 7.6 | 9.6 |
| Other (e) | 267 | 556 | 13,962 | 1 | 142.5 | 162.0 |
| Total | 1,579 | 1,091 | 91,037 | 10 | 338.2 | 274.8 |

(a) The Lavaca System was acquired effective January 31, 2014.
(b) The gathering and processing assets of Costar Midstream were acquired effective October 1, 2014.
(c) This includes the crude oil gathering system in the Williston Basin with capacity of 40,000 bbl/d which commenced operation in October 2015. From October 2015 through December 2015, the Bakken system had average throughput volumes of 8,639 Bbl/d.
(d) We have included approximate average throughput at 100% for the Chatom System. As of December 31, 2015, we owned 92.2% undivided interest in the Chatom System.
(e) Other includes our Gloria and Lafitte, Quivira and Burns Point, and Offshore Texas systems.

Lavaca System

The Lavaca System consists of 203 miles of high- and low-pressure pipelines ranging from four to eight inches in diameter with 32,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The Lavaca System currently has a design capacity of approximately 218 MMcf/d. Natural gas production gathered by the system is compressed and delivered to a third-party for processing or redelivered to producers for gas lift.

Magnolia System

The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coal-bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transcontinental Gas Pipe Line Co. pipeline system ("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.

Longview System

The Longview gathering and processing system consists of approximately 620 miles of high- and low-pressure gathering lines with diameters ranging from two to twenty inches with a combined compression capacity of 23,880 horsepower. Our Longview System also contains two cryogenic processing plants with a design capacity of approximately 50 MMcf/d, one fractionation unit with 8,500 Bbls/d of capacity, product storage tanks, and truck racks to receive off-spec condensate. The Longview System is located near Longview in Gregg County, Texas. Located adjacent to the Longview System is a rail facility, which is currently under construction, that will transport off-spec condensate. This facility commenced operations in the first quarter of 2016.

Chapel Hill System

The Chapel Hill gathering and processing system consists of approximately 90 miles of gathering lines with a combined compression capacity of 2,540 horsepower. Our Chapel Hill System also contains a cryogenic processing plant with a design capacity of approximately 20 MMcf/d, one fractionation unit with 1,250 Bbls/d of capacity, product storage tanks, and truck racks to deliver propane. The Chapel Hill System is located near Tyler in Smith County, Texas.

Yellow Rose System

The Yellow Rose gathering and processing system consists of approximately 47 miles of low-pressure, rich-gas gathering system and 40 MMcf/d cryogenic processing plant that commenced operations in October, 2014. The Yellow Rose System is located in Martin County, Texas.

Bakken System

The Bakken crude oil gathering pipeline system consists of a 43 mile pipeline with capacity to transport up to approximately 40,000 Bbls/d of crude oil for delivery to the Tesoro Logistics pipeline located Northeast of Watford City, North Dakota and a planned interconnect with the Energy Transfer Dakota Access Pipeline. The system, which commenced operations in October 2015, provides producers in the area with access to refinery, rail and pipeline markets. The system also has the capability to receive volumes through its truck rack, which also commenced operations in November 2015. From October 2015 through December 2015, the Bakken system had average throughput volumes of 8,639 Bbl/d.

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 and compression capacity of 3,456 horsepower. 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 crude oil and natural gas wells in the Norphlet and Smackover formations in Alabama and Mississippi. Chatom also has a truck rack and the capability to provide condensate stabilization services.

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. The natural gas supply for our Bazor Ridge System is derived primarily from rich natural gas produced from crude oil wells targeting the mature Upper Smackover formation.

Other Gathering and Processing Systems

Gloria and Lafitte systems. 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 may experience excess volumes from our Lafitte system. The Lafitte gathering system consists of approximately 40 miles of gathering pipeline, with diameters ranging from four to 12 inches and a design capacity of approximately 71 MMcf/d. The Lafitte System originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana, at the Alliance Refinery owned by Phillips 66. 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 Phillips 66 at the Alliance

Refinery is delivered to our Gloria System.

Quivira and Burns Point Systems. 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 Gas Processing, LLC ("Enterprise"). We hold a 50% undivided, non-operated interest in the Burns Point Plant. We acquired an interest in the asset group and not in a legal entity. We and Enterprise are 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 and have approximately 56 miles of pipeline with diameters ranging from six to 16 inches and a design capacity of approximately 100 MMcf/d. The Offshore Texas System is in a position to provide gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico offshore Texas.

Customers and Contracts

With respect to our Gathering and Processing segment, substantially all of the natural gas produced on our Lavaca System is delivered to Penn Virginia Corporation for processing. On our Gloria and Lafitte systems, we have a buy/sell agreement whereby most of the natural gas is sold to ConocoPhillips for use at the Alliance Refinery in Plaquemines Parish, Louisiana, under a contract that expires in 2023. For the year ended December 31, 2015, our Gathering and Processing segment derived 12% of its revenue from both ConocoPhillips and Penn Virginia, respectively. For the year ended December 31, 2014, our Gathering and Processing segment derived 33% and 12% of its revenue from ConocoPhillips 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 or production points 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, including onshore and offshore producing regions around southeast Louisiana, and multiple counties in Mississippi, Alabama and Tennessee.

The following table provides information regarding our Transmission segment assets as of December 31, 2015, and for the years ended December 31, 2015 and 2014.

| | Approximate Transmission System (Miles) | Jurisdiction | Compression (Horsepower) | Approximate Design Capacity (MMcf/d) | Approximate Average Throughput (MMcf/d) Years Ended December 31, | |
|---|---|---|---|---|---|---|
| | | | | | 2015 | 2014 |
| Transmission | | | | | | |
| High Point | 574 | Intrastate | — | 1,120 | 371.6 | 427.3 |
| Midla/MLGT (a) | 432 | Interstate/Intrastate | 3,600 | 518 | 139.7 | 183.8 |
| AlaTenn/Bamagas/TriGas | 383 | Interstate/Intrastate | 3,665 | 710 | 182.7 | 160.3 |
| Chalmette | 39 | Intrastate | — | 125 | 14.6 | 7.5 |
| Total | 1,428 | | 7,265 | 2,473 | 708.6 | 778.9 |

(a) Includes the SIGCO system.

High Point System

The High Point System consists of approximately 574 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 63 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on crude 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, which is operated by Enterprise, where the products are processed and the residue gas is sent to an unaffiliated interstate system owned by Kinder Morgan Energy Partners.

Midla and MLGT Systems

9

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.

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.

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.

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.

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 Corporation 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 five receipt and 19 delivery points.

On April 16, 2015, the FERC approved the Midla Agreement between Midla and its customers allowing Midla to retire the existing 1920s vintage pipeline and replace the existing natural gas service with a new pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the “Midla-Natchez Line”) to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. On June 29, 2015, the Partnership filed for authorization to construct the Midla-Natchez pipeline with the FERC, which was approved on December 17, 2015. Construction is expected to commence in the first half of 2016 with service beginning in late 2016. Under the Midla Agreement, Midla plans to execute long-term agreements seeking to recover its investment in the Midla-Natchez Line.

We also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

AlaTenn/Bamagas/Trigas

AlaTenn System. The AlaTenn System is a FERC-regulated 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 294 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 19 active delivery and four receipt 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.

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 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. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements.

Trigas System. Our Trigas System is located in three counties in northwestern Alabama and has approximate design capacity of 60 MMcf/d.

Chalmette System

The Chalmette System is located in St. Bernard Parish, Louisiana. The approximate design capacity for the Chalmette System is 125 MMcf/d.

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.

For our Midla and AlaTenn systems, and a portion of our High Point 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 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.

For our High Point systems, we have interruptible transportation contracts in place with various customers operating in both onshore and offshore producing regions around southeast Louisiana. During 2015, we converted a fixed-margin arrangement on our MLGT System to an interruptible transportation contract, which has reduced the amount of natural gas that we transport.

Within the Transmission segment, the weighted-average remaining life of our firm and interruptible transportation contracts is approximately five years and less than one year, respectively. Superior Natural Gas Corporation 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 19% and 16%, respectively, of our segment revenue for the year ended December 31, 2015. For the year ended December 31, 2014, ExxonMobil and Enbridge Marketing (US) L.P. accounted for approximately 43% and 16%, respectively, of our segment revenue.

Terminals Segment

General

Our Terminals segment consists of approximately 1.8 million barrels of storage capacity across three marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; and Harvey, Louisiana. 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 petroleum products, distillates, chemicals and agricultural products.

The following table provides information regarding our Terminals segment assets as of December 31, 2015, and for the years ended December 31, 2015 and 2014.

| | | | | Storage Utilization (%) As of December 31, | |
|---|---|---|---|---|---|
| Terminals | Number of Tanks | Approximate Contracted Capacity (Bbls) | Approximate Design Capacity (Bbls) | 2015 | 2014 |
| Westwego | 48 | 981,400 | 1,044,600 | 93.9% | 100.0% |
| Brunswick | 5 | 221,000 | 221,000 | 100.0 | 100.0 |
| Harvey (a) | 21 | 390,000 | 535,200 | 72.9 | 16.4 |
| Total | 74 | 1,592,400 | 1,800,800 | 88.4% | 86.8% |

(a) The Harvey terminal commenced operations in July of 2014.

Westwego Terminal Operations

The Westwego Terminal site consists of 48 above-ground storage tanks with a combined capacity of 1,044,600 barrels. 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 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 with a combined capacity of 221,000 barrels. The Brunswick Terminal is currently leasing land from the Georgia Ports Authority pursuant to a lease that is scheduled to terminate on September 4, 2016, which we plan to renew.

This terminal is ideally suited to serve petroleum, chemical and agricultural customers who need deep-water access and distribution in the southeastern United States. 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 is located on 56 acres on the west bank of the Mississippi River in the Port of New Orleans and equipped to handle a wide variety of petroleum and chemical products. Terminal storage operations at the Harvey Terminal commenced in July 2014 and currently consists of 21 above-ground storage tanks with a combined capacity of approximately 535,200 barrels. The Harvey Terminal is a full-service storage site, including 3,000 feet of rail track that can accommodate up to 50 cars, a two bay semi-automated truck loading facility, and a deepwater shipdock allowing for product transfers via ship, barge, railcar, and/or tank truck. The Partnership recently executed an agreement with a major refinery customer to lease 650,000 barrels of storage capacity at the Harvey Terminal, of which 550,000 will be newly constructed, increasing the site's total storage capacity to approximately 1.1 million barrels by the end of 2016. When fully developed, the Harvey Terminal has the potential to provide more than 2 million barrels of storage capacity.

Customers

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.

Among all of our customers in this segment, the weighted-average remaining life of our guaranteed firm storage contracts are approximately 2.2 years. Occidental Chemical Corporation and Monsanto Company are the two largest customers in our Terminals segment and accounted for approximately 21% and 13%, respectively, of our segment revenue for the year ended December 31, 2015. Shell Trading (US) Company and Shrieve Chemical Products, Inc accounted for approximately 20% and 19%, respectively, of our segment revenue for the year ended December 31, 2014.

Investment in Unconsolidated Affiliates

Delta House

We own a 12.9% non-operated indirect interest in Delta House, a semi-submersible floating production system (“FPS”) with associated crude oil and natural gas export pipelines located in the Mississippi Canyon region of the deepwater Gulf of Mexico. The FPS receives raw production from deepwater wells, which includes a mixture of crude oil, natural gas, and produced water, and separates the production into its components. The separated crude oil and natural gas pressures are increased, creating pipeline quality crude oil and natural gas that flows into the respective crude oil and natural gas export pipelines. Delta House is operated by LLOG Exploration and has nameplate processing capacity of 80,000 Bbl/d and 200 MMcf/d and peak processing capacity of 100,000 Bbl/d and 240 MMcf/d.

Main Pass Oil Gathering System

We own a 66.7% non-operated interested in MPOG, a crude oil gathering system located offshore the Southeast coast of Louisiana in the Gulf of Mexico. The approximately 100 mile system has a total design capacity of approximately 160,000 Bbl/d and is currently operated by Panther Operating Companies, LLC, a subsidiary of the minority interest owner, Panther Companies.

Mesquite

We own a 46% non-operated interest in Mesquite, a joint venture with EnLink Midstream located near Midland, Texas. The Mesquite facility includes a rail terminal, 5,000 Bbl/d condensate stabilization facility and 5,000 Bbl/d fractionation unit that facilitates the receipt, treatment and sale of off-spec condensate and NGLs via pipeline, truck and rail.

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 DCP Midstream LLC; Enbridge Energy Partners; LP; Energy Transfer Partners, L.P; EnLink NGL Marketing, L.P.; Kinder Morgan Energy Partners; Midcoast Energy Partners, and Southcross Energy Partners, L.P.

Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for natural gas, crude oil 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.

In our Transmission segment, we compete with other pipelines that serve regional markets, specifically in our Baton Rouge market. An increase in competition could result from new pipeline installations or expansions of existing pipelines. Competitive factors include the commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and natural gas quality issues. Our major competitors for this segment are Columbia Gulf Transmission Company; EnLink NGL Marketing, L.P.; Enterprise Gas Processing, LLC; Gulf South Pipeline Company, LP; Southern Natural Gas Company; Tennessee Gas Pipeline Company, LLC, and Texas Eastern Pipeline.

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 International-Matex Tank Terminals; Kinder Morgan Energy Partners; LBC Tank Terminals; Royal Vopak; Stolt-Nielsen Limited, and Westway Terminals Company LLC.

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. crude 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. In April 2015, PHMSA proposed rulemaking that would require leak detection for all hazardous liquid pipelines and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. A final rule has not been issued. To date, PHMSA has not proposed rules expanding the integrity management requirements for natural gas 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 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 states 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 crude 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 ("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 ("EPA"), community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act (Superfund") 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 that 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 crude oil pipelines using FERC's Discounted Cash Flow ("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 natural gas and crude oil 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 FERC's 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 that 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, ("EP Act 2005"). Among other matters, the EP Act 2005 amended the NGA to add an anti-manipulation provision that 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 EP Act 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 EP Act 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 EP Act 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 crude 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 crude 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 ("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"), 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.

Air Quality and Climate Change

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. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than to any similarly situated company. As the EPA issues new, lower National Ambient Air Quality Standards ("NAAQS"), we may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, in June 2010, the EPA issued a new NAAQS for sulfur dioxide, or SO2, and replaced the 24-hour and annual standards with a more stringent hourly standard. In October 2015, the agency finalized a reduction of the national ambient air quality standard for ozone standard from 75 parts per billion to 70 parts per billion; both nitrogen oxides and VOCs are ozone precursors. This reduction is expected to increase the number of ozone nonattainment areas. In September 2015, the EPA also proposed Control Technology Guidelines for emissions of VOCs from crude oil and natural gas industry sources to be relied upon by states when implementing the ozone standard in ozone nonattainment areas. We believe 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.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for crude oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. The established specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. Initial compliance and ongoing compliance with the new subset of rules required capital expenditures and ongoing compliance expenses. 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. The EPA issued revised definitions related to the stages of well completions and amended storage tank requirements under NSPS Section OOOO in December 2014 and further revised the storage tank requirements in March 2015. The EPA continues to reconsider other portions of Section OOOO. The rule is also the subject of Petitions for Review before the U.S. Court of Appeals for the District of Columbia Circuit.

A number of states have adopted or considered programs to reduce “greenhouse gases,” or GHGs and the EPA has declared that GHGs “endanger” public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks. According to the EPA, this final action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. These requirements for stationary sources took effect on January 2, 2011; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases. Large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. In December 2014, the EPA proposed to amend and expand greenhouse gas reporting requirements to all segments of the oil and gas sector, with a final regulation expected to be effective by January 1, 2016 with initial reporting submitted by March 31, 2017 for all affected sources.

In September of 2015 the EPA released proposed rules to set emission standards for methane and volatile organic compounds, or VOCs, for certain new, modified and reconstructed emission sources across the oil and gas sector. The proposed rules affect sources that had VOC requirements under the 2012 NSPS rule but now this is to include methane for these sources. For sources not affected by the 2012 rule the proposed rule will implement VOC and methane standards for those sources. The proposed rules apply to facilities constructed, modified or reconstructed after September 1, 2015 and would include 2012 rules as well as new provisions within the 2015 proposed rules. In particular the rules affect centrifugal and reciprocating compressors, pneumatic pumps, fugitive emissions from well sites and compressor stations and equipment leaks at natural gas processing plants. Additionally, in January 2016, the Bureau of Land Management proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which are expected to be finalized in 2016.

The permitting, regulatory compliance and reporting programs taken as a whole increase the costs and complexity of operating oil and gas operations in compliance with these legal requirements, with resulting potential to adversely affect our cost of doing business, demand for the oil and gas we transport and may require us 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.

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. In May 2015, the EPA and the U.S. Army Corps of Engineers issued a final rule to clarify which waters and wetlands are subject to Clean Water Act regulation. The implementation of this rule was stayed nationwide in October 2015. 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 ("SPCC") 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 crude 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 that result in a shorter NEPA review process. The Council on Environmental Quality has issued final guidance to reinvigorate NEPA reviews that, 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.

Anti-terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present “high levels of security risk.” Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Title to Properties and Rights-of-Way

Our real property falls into two categories: i) parcels that we own in fee and ii) 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, 2015, our General Partner employed approximately 300 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 positive.

## General

We make certain filings, and amendments thereto, with the Securities and Exchange Commission (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, results of operations or cash flows 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 Agreement includes financial covenants and ratios. We may have difficulty maintaining compliance with such financial covenants and ratios, which include a consolidated total 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 working capital and future expansion capital needs and, as necessary, to fund a portion of cash distributions to unitholders. We are required to comply with certain financial covenants and ratios in our Credit Agreement, including a consolidated interest coverage ratio, consolidated total leverage ratio and consolidated secured leverage ratio. 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 Agreement could result in a default, which could cause all of our existing indebtedness to become immediately due and payable.

Our ability to pay distributions to holders of our common and Series A Units is partially dependent upon general economic conditions in the energy industry, which continue to deteriorate.

The actual amount of cash that is available to be distributed each quarter depends, in part, upon general economic conditions in the energy industry, which are beyond our control and the control of our General Partner. As conditions in the energy industry have continued to deteriorate many master limited partnerships have decreased the amount of, or suspended the payment of, distributions to holders of common units. If the current state of the energy industry continues for a prolonged period of time, or the condition worsens, we may be forced to reduce or suspend distributions to holders of our common and Series A Units.

We may not have sufficient cash from operations following the preferred distribution on our Series A Units, the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, to enable us to pay distributions to holders of our common units.

We may not have sufficient available cash from operations each quarter to enable us to pay the minimum quarterly distribution of $0.4125 per common unit or at all. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our Series A 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 crude oil and natural gas and the resultant market prices of crude oil and natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- changes in the fees we charge for our services;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- the effect of seasonal variations in temperature on the amount of natural gas and crude oil that we transport and the amount of natural gas that we store, process and treat;
- 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 creditworthiness of our customers;
- the level of our operating, maintenance and selling, 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 and timing of capital expenditures we make;
- the cost of acquisitions, and the resulting costs of integrations, if any;
- our debt service payments and requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our Credit Agreement;
- the amount of cash reserves established by our General Partner; and
- other business risks affecting our cash levels.

There is no guarantee that unitholders will receive quarterly distributions from us. Our distributions are determined each quarter by the Board of Directors of our General Partner based on the board's consideration of the foregoing factors, our financial position, earnings, cash flow, current and future business needs and other relevant factors at that time. We may reduce or eliminate distributions at any time we have insufficient cash available for distributions. This may be due to insufficient cash reserves, requirements to fund current or anticipated future operations, capital expenditures, acquisitions, growth or expansion projects, debt repayment or other business needs.

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, NGLs and crude oil, 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 commodity volumes that support our business are dependent on the level of production from natural gas and crude 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 and crude oil. The primary factors affecting our ability to obtain non-dedicated sources of natural gas and crude oil 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:

- prevailing and projected natural gas, crude oil and NGL prices;
- the availability and cost of capital;
- demand for natural gas, crude oil 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, like the ongoing declines in commodity prices of crude oil, natural gas and NGLs, can also greatly affect the development of new reserves. Further declines in crude oil, natural gas and NGLs prices could have a negative impact on exploration, development and production activity, and, if sustained, are likely to lead to further decreases in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices continue to remain low or trend lower as they have since the latter part of 2014, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our Credit Agreement. Reduced profitability may also result in future non-cash impairments of long-lived assets, goodwill, or intangible assets.

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

Natural gas, crude oil, 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. Natural gas prices have been under downward pressure in recent years and were highly volatile in 2014. The NYMEX daily settlement price for natural gas for the forward month contract in 2015 ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu. NGL prices are generally positively correlated to the price of WTI crude oil, which has also exhibited frequent and substantial fluctuations. Oil prices declined dramatically in late 2014 and remained low in 2015 and early 2016. The NYMEX daily settlement price for WTI crude oil for the forward month contract in 2015 ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl.

The markets for and prices of natural gas, crude oil, 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 world-wide and domestic production and consumer demand;
- the availability of imported, or market for exported, liquefied natural gas, or LNG;
- the market for exported crude oil;
- 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 current and anticipated future prices of natural gas, crude oil, 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, NGLs and crude oil 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, 2015 and 2014, percent-of-proceeds arrangements accounted for approximately 14.1% and 25.6%, respectively, of our gross margin, or 22.7% and 51.7%, respectively, of the segment gross margin in our Gathering and Processing segment.

If the current decline in commodity prices continues, it could result in a further decrease in exploration and development activities in the fields served by our gathering and pipeline transmission systems and our natural gas processing plants, which could lead to further reduced utilization of these assets. During periods of natural gas, crude oil, or NGL declines, the level of drilling activity generally decrease. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers' borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers' spending for drilling activity, which could result in lower volumes being transported on our gathering and transmission systems.

Our growth strategy, and ability to fund expansion capital projects, requires access to new capital. Tightened capital markets or other factors that increase our cost of capital, or limit our access to capital, could impair our ability to grow.

We continuously consider potential acquisitions and opportunities for expansion capital projects. Acquisition opportunities arise quickly and unexpectedly, may occur at any time and may be significant in size relative to our existing assets and operations. Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile, including our target debt-to-equity ratio, could affect our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements, our Credit Agreement or capital markets on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plans, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

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.

From time to time, we have entered into derivative transactions related to only a portion of the equity volumes of commodities to which we take title. As a result, we will continue to have direct commodity price risk to the unhedged portion of our commodity equity volumes. We do not currently have any commodity hedges in place and whether we place additional commodity hedges depends on the cost of such hedges, our projected volumes and price expectations. 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 commodity prices that we realize in our operations. In addition, when there is not a hedging instrument available for a commodity to which we take title, we are forced to use an alternative hedge that may not adequately reduce price risk. 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. Further, there may be times where we terminate or enter into offsetting positions depending on our view of future market prices. We do not enter into derivative transactions with respect to the volumes of natural gas or condensate that we purchase and sell.

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

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

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

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

We have no control over the entities that own and operate Delta House.

We recently acquired a 26.3% non-operated interest in Pinto Offshore Holdings, LLC ("Pinto"), an entity that owns a non-operated interest in (i) approximately 49% of the limited liability company interests of Delta House FPS LLC and (ii) approximately 49% of the limited liability company interests of Delta House Oil and Gas Lateral LLC, which respectively own the Delta House floating production system and related pipeline infrastructure ("Delta House"). As a result, we own a minority interest in Pinto, which in turn causes us to own a 12.9% indirect interest in Delta House. Pursuant to the limited liability company agreement of Pinto, we have no management control or authority over the day-to-day operations, capital calls, expenditures, expansions or any other decision with regard to Delta House and its related infrastructure. We may be required to make significant capital contributions to Delta House, or risk dilution of our indirect investment. In the event Delta House does not perform to expectations, we do not have any ability to make changes in its operations.

Severe weather in the U.S. Gulf of Mexico, including windstorms, could cause significant damage and disruption to our business interests located in that region.

The U.S. Gulf of Mexico experiences hurricanes and other extreme weather conditions on a frequent basis, the frequency of which may increase with climate change. Our High Point system, our Offshore Texas system, our non-operated interests in MPOG and Delta House and any future systems that we acquire in the U.S. Gulf of Mexico, are susceptible to adverse weather conditions in the U.S. Gulf of Mexico, including hurricanes and other extreme weather conditions. Our insurance may not cover all associated loss. High winds, storm surge, and turbulent seas can cause significant damage and curtail these operations for extended periods during and after such weather conditions, which may result in decreased revenues from our interests in these operations. In addition, these adverse weather conditions in the U.S. Gulf of Mexico can affect producers connected to our facilities even if our facilities are not damaged, which may result in decreased revenues from our interests in these operations.

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. 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.

We are a relatively small enterprise, and our management has limited history and experience with certain aspects of our business and certain 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, volume reduction or other event that might 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 certain aspects of our business and certain 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 extensive 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 have identified a material weakness in our internal control over financial reporting, and our business and unit price may be adversely affected if we do not adequately address the weakness or if we have other material weaknesses or significant deficiencies in our internal control over financial reporting.

We identified a material weakness in our internal control over financial reporting as of December 31, 2014 related to the failure to design and maintain effective internal controls over the completeness and accuracy of spreadsheets. Our guidelines were not precise enough in describing the level of review to be performed regarding the inputs, assumptions and formulas used in spreadsheets. The existence of this or other material weaknesses or significant deficiencies could result in errors in our financial statements, and substantial costs and resources may be required to rectify any internal control deficiencies. Although the material weakness identified above had been remediated as of December 31, 2015, if we cannot produce reliable financial reports, investors could lose confidence in our reported financial information, the market price of our common units could decline significantly, we may be unable to obtain additional financing to operate and expand our business and our business and financial condition could be harmed.

We continue to evaluate the adequacy of our accounting personnel staffing level and other matters related to our internal control over financial reporting, and we cannot predict the outcome of this evaluation of the effectiveness of our internal control over financial reporting.

Given the difficulties inherent in the design and operation of internal control over financial reporting, 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 of the Sarbanes-Oxley Act of 2002. Any failure to implement and maintain effective internal control 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 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 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, 2015, our Gathering and Processing segment derived 12% of its revenue from both ConocoPhilips Company and Penn Virginia Oil & Gas, LP. For the year ended December 31, 2014, our Gathering and Processing segment derived 33% and 12% of its revenue from ConocoPhillips Company and Shell Trading (US) Company, respectively. For the year ended December 31, 2015, our Transmission segment derived 19% and 16% of its revenue from Superior Natural Gas Corporation and Enbridge Marketing (US) L.P., respectively, who were the two largest purchasers of natural gas and transmission capacity. For the year ended December 31, 2014, ExxonMobil and Enbridge Marketing (US) L.P. accounted for approximately 43% and 16%, respectively, of our Transmission segment revenue. Occidental Chemical Corporation and Monsanto Company accounted for 21% and 13%, respectively, of our Terminal segment revenue for the year ended December 31, 2015. Shell Trading (US) Company and Shrieve Chemical Products, Inc. accounted for 20% and 19%, respectively, of our Terminal segment revenue for the year ended December 31, 2014.

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. 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.

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, crude 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 commodities 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.

Environmental, health and safety costs and liabilities, and changing environmental, health and safety regulation, could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety regulations will not be revised or that new regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, future environmental, health and safety law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations. Areas of potential future environmental, health and safety law development include the following items:

Greenhouse Gases/Climate Change. The U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content.

The EPA initiated the regulation of greenhouse gases under its Clean Air Act authority in 2009, as set forth in the discussion of new rules below. Federal agencies also have begun directly regulating emissions of methane (a greenhouse gas) from crude oil and natural gas operations. In September 2015, the EPA announced proposed new source performance standards for methane from new and modified crude oil and natural gas industry sources, which are expected to be finalized in 2016. These regulations will expand upon the 2012 EPA new source performance standard rulemaking for equipment-specific emissions control requirements, and will, for example, require additional controls for pneumatic controllers and pumps, and compressors, and impose leak detection and repair requirements for natural gas compressor and booster stations. In January 2016, the Bureau of Land Management proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which also are expected to be finalized in 2016.

The adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the commodities that we buy and/or sell, transport, store or otherwise handle in connection with our midstream services. In addition, the adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, the equipment and operations of our producer customers could affect their ability to produce the commodities that we buy and/or sell, transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include among other things costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

Hydraulic Fracturing. Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas and crude oil production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The U.S. federal government, and some states and localities, have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production, or otherwise limit the use of the technique. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to crude oil and natural gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of crude oil and natural gas incurred by our customers or could make it more difficult for them to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling or production of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and have a material adverse effect on our financial position, results of operations and cash flows.

The value of our interests in operations located in the U.S. Gulf of Mexico could be adversely impacted by increased regulation and continuing regulatory uncertainty.

Operations in the U.S. Gulf of Mexico have been subject to an increasingly stringent regulatory environment including government regulations focused on offshore operating requirements, spill cleanup, and enforcement matters. These regulations also implement additional safety and certification requirements applicable to offshore activities in the U.S. Gulf of Mexico. Certain operating assets such as our High Point system and our Offshore Texas system, and certain non-operated interests in operations located in the U.S. Gulf of Mexico that we currently hold or may hold in the future, are subject to such increased regulations, including our non-operated interests in MPOG and Delta House. In addition, the Bureau of Safety and Environmental Enforcement and the Bureau of Ocean Energy Management has increased regulatory activity including shortening the time period a line may be inactive before it must be removed or abandoned and requiring additional supplemental bonding for offshore facilities. These new regulations have increased our operating costs, and the operating costs of our producer customers. As a result, the value of our interests in these operations may be adversely affected by these regulations. Future regulatory requirements could delay activities from these operations and reduce our revenues, resulting in reduced cash flows and profitability.

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 have 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 $0.6 million during 2016 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 April 2015, PHMSA proposed rulemaking that would require leak detection for all hazardous liquid pipelines and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. A final rule has not been issued. To date, PHMSA has not proposed rules expanding the integrity management requirements for natural gas pipelines. 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 or attractive 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, decline rates, drilling activity and cost savings, 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 certain 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;
- the entry of competitors in the markets where the acquired business competes;
- 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 managements 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 environmental laws and regulations relating to the release of pollutants into the environment and environmental protection that 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 increased revenue 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. Cost overruns on construction projects may cause unexpected changes in project economics. 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 crude 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.

In connection with our expansion capital programs, we have agreed, and may in the future agree, to construct oil and gas gathering pipelines to service existing and future oil and gas properties, which involves potential risks.

In connection with our expansion capital programs, we have agreed, and may in the future agree, 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 producing crude oil and natural gas properties. 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 producer'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
- title issues or environmental or regulatory compliance matters or liabilities or accidents associated with the construction or operation of the pipelines.

We currently expect to fund these costs with borrowings under our Credit Agreement or by accessing the capital markets. 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 crude oil and natural gas properties 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 EP Act 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 EP Act 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 CERCLA 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 Clean Water Act and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal OPA and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- the federal RCRA and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;
- the 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.

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 Quality and Climate Control" 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.

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. The EPA argued that these motor vehicle regulations triggered the regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. In June 2014, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases. Large sources of other air pollutants which are otherwise required to go through permitting, still could be required to implement process or technology controls designed to reduce emissions of greenhouse gases in order to obtain a permit.

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. In October 2015, the EPA amended and expanded greenhouse gas reporting requirements to all segments of the crude oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, starting with the 2016 reporting year, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rule with the new source performance standards. We have filed annual emission reports for our Bazor Ridge and Chatom systems since March 2012.

As discussed in the climate change section above, EPA also has initiated regulation of methane from crude oil and natural gas facilities. Final rules are expected in 2016. It is likely that we will be required to control methane emissions from new or modified facilities under this rulemaking.

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. The EPA issued revised definitions related to the stages of well completions and amended storage tank requirements under NSPS Section OOOO in December 2014 and further revised the storage tank requirements in March 2015. EPA continues to reconsider other portions of Section OOOO. The rule is also the subject of Petitions for Review before the U.S. Circuit Court of Appeals for the District of Columbia.

In October 2015, the EPA finalized a reduction of the national ambient air quality standard for ozone standard from 75 parts per billion to 70 parts per billion; both nitrogen oxides and VOCs are ozone precursors. This reduction is expected to increase the number of ozone nonattainment areas. The EPA also proposed in September 2015 Control Technology Guidelines for emissions of VOCs from crude oil and natural gas industry sources to be relied upon by states when implementing the ozone standard in ozone nonattainment areas.

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 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, in April 2015, PHMSA proposed rulemaking that would require leak detection for all hazardous liquid pipelines and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. A final rule has not been issued. To date, PHMSA has not proposed rules expanding the integrity management requirements for natural gas 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.

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, who does not devote 100% of their time to us. 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 similar 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 or its affiliates, which means they do not devote 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 and crude oil 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 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 and crude oil 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 these systems 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, or 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.

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.

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, reduced government spending, 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.

Risks Related to Our Units, Partnership 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 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, our Credit Agreement, applicable state business organization laws and other laws and regulations.

The amount of cash we have available for distribution to holders of our common and Series A 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 net losses for financial reporting purposes and may not make cash distributions during periods when we record net income for financial reporting purposes.

The amount of cash we have available for distribution to holders of our common and Series A Units is subject to the broad discretion of our General Partner to set aside reserves for our conduct of business and for the payment of future distributions.

The amount of cash we have available for distribution is subject to our General Partner’s determination to set aside reserves for (i) conducting business, including anticipated capital expenditures, during the next quarter, (ii) compliance with any law or agreement and (iii) distributions for the next four quarters. As a result, we may make cash distributions during periods when we record net losses for financial reporting purposes and may not make cash distributions during periods when we record net income for financial reporting 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.

HPIP, an affiliate of ArcLight Capital Partners, and AIM Midstream Holdings, LLC ("AIM Midstream Holdings") directly own our General Partner, which has sole responsibility for conducting our business and managing our operations. HPIP elects all of the members of the board of our General Partner. HPIP, 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.

HPIP and AIM Midstream Holdings own our General Partner. HPIP has the power to appoint all of the officers and directors of our General Partner, some of whom are also officers of HPIP. The directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner that is beneficial to it, and have no duty to us or our common unitholders. Conflicts of interest may arise between HPIP 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 HPIP 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 HPIP 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 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 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 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 ("Conflicts Committee") or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our President and Chief Executive Officer received a grant of phantom units, with distribution equivalent rights based on Series A distributions, in connection with his appointment.

In December 2015, Lynn L. Bourdon, our President and Chief Executive Officer received a grant of 200,000 phantom units with distribution equivalent rights. The distribution equivalent rights receive cash distributions based on the extent to which the Series A Units receive cash distributions. Holders of Series A Units have different incentives than holders of our common units and therefore Mr. Bourdon’s incentives may not always align with those of our common unit holders.

HPIP 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.

HPIP 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, HPIP 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 HPIP 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.

Our common units are listed 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.

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 net 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 for the units 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 rely primarily upon external financing sources, including borrowings under our Credit Facility 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 Agreement, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional borrowings under our Credit Agreement 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 us and the holders of our common units.

Our Partnership Agreement contains provisions that modify and reduce the fiduciary duties 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 HPIP. 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 4, 2016, HPIP owned 6,650,214 Series A Units and controlled our General Partner which held 1,349,609 common units. If the Series A Units were converted, HPIP's holdings would represent 22.6% of our then-outstanding common units. As of March 4, 2016, Magnolia Infrastructure Partners, LLC ("Magnolia"), an affiliate of HPIP, owned 2,849,156 Series A Units and Busbar, LLC ("Busbar"), an affiliate of HPIP, owned 1,629,450 of our common units.

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

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors of our General Partner, cannot vote on any matter.

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

Our General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of HPIP 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 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.

HPIP 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.

As of March 4, 2016, HPIP held 6,650,214 Series A Units. The Series A Units are convertible into common units at the election of HPIP at any time. In addition, as of March 4, 2016, HPIP and AIM Midstream Holdings controlled our General Partner, which held 1,349,609 common units. As of March 4, 2016, Magnolia owned 2,849,156 Series A Units and 618,921 of our outstanding common units and Busbar owned 1,629,450 of our outstanding 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 our 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 4, 2016, HPIP owned 6,650,214 Series A Units and controlled our General Partner which held 1,349,609 common units. If the Series A Units were converted, HPIP's holdings would represent 22.6% of our then-outstanding common units. As of March 4, 2016, Magnolia owned 618,921 our outstanding common units and Busbar owned 1,629,450 of our outstanding common units.

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

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

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute "control" of our business.

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

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

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include a 26.3% non-operated interest in Pinto, which may be deemed to be an "investment security" within the meaning of the Investment Company Act of 1940, as amended (the “Investment Company Act”). In the future, we may acquire additional minority owned interests that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business. Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

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 ("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 the 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 the 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 that allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for 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 and the President's Administration have recently considered substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Further, on May 5, 2015, the U.S. Treasury Department (“Treasury”) and the IRS issued proposed regulations interpreting the scope of activities that generate qualifying income under Section 7704 of the Internal Revenue Code of 1986, as amended (the “Code”). We believe that the income we currently treat as qualifying income satisfies the requirements for qualifying income under the proposed regulations. The proposed regulations, however, could be changed before they are finalized and could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement. 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 0.75% of taxable margin apportioned to Texas. Imposition of such a tax on us by other states would reduce the cash available for distribution to unitholders. 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.

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. 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. The costs of these audits are borne indirectly by the unitholders and our general partner because such costs reduce our cash available for distribution.

If the IRS contests the federal 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 the unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. We received a Notice of Beginning of Administrative Proceeding from the IRS in October 2014 relating to our 2012 tax year, however, the audit was concluded in June 2015 with no proposed adjustments. 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. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS, and the outcome of any such contest, may increase a unitholder's tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our common units and the price at which they trade. The rights of a unitholder owning less than a 1% profits interest in us to participate in the federal income tax audit process are very limited. In addition, our costs of any contest with the IRS will be borne indirectly by the unitholders and our General Partner because such costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess us for any taxes (including any applicable penalties and interest) resulting from such audit adjustment and collect such taxes directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess us for any taxes (including any applicable penalties and interest) resulting from such audit adjustment and collect such taxes directly from us. We expect to have the ability to shift any such tax liability to our General Partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

The unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if the unitholders 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. The unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the federal income tax liability of unitholders.

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.

There are limits on the deductibility of losses that may adversely affect unitholders.

In the case of taxpayers subject to the passive loss rules (generally, individuals, closely-held corporations and regulated investment companies), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of the unitholder’s entire investment in us in a fully taxable transaction with an unrelated party. A unitholder’s share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships.

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

If a unitholder sells its 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 with respect to the units sold 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 its 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, or IRAs, 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 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 treat each purchaser of our 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 have adopted 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 the 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 the 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. Treasury recently adopted final 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 to ours. We are currently evaluating these regulations, which apply to certain publicly-traded partnerships, including us, for taxable years beginning on or after August 3, 2015. However, these regulations do not specifically authorize the use of the proration method we have previously used. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among the 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, the unitholder would no longer be treated for 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, the unitholder may no longer be treated for 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 and lending their common units.

We have adopted certain valuation methodologies for tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and the 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 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 the 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 the 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 Code 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 the unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to the unitholders. It also could affect the amount of gain from the unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the 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 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 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, such a 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 relief procedure for publicly traded partnerships that terminate in this manner, whereby, if a publicly traded partnership that has 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 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 do 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, local and non-U.S. tax returns. Our outside tax 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 property 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.

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 is incorporated into this Item 2. by reference.

Our principal executive offices are located at 1400 16th Street, Suite 310, Denver, Colorado 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 to 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.

Item 4. Mine Safety Disclosures

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 ("NYSE") since July 27, 2011, under the symbol "AMID." The following table sets forth the high and low sales prices of our common units, as reported by the NYSE for each quarter during 2015 and 2014, together with distributions paid subsequent to such quarter for that quarter through December 31, 2015:

| Period Ended | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
|---|---|---|---|---|
| 2015 | | | | |
| High Price | $12.70 | $16.71 | $19.42 | $21.17 |
| Low Price | $3.80 | $9.01 | $15.75 | $15.71 |
| Distribution per common unit | $0.4725 | $0.4725 | $0.4725 | $0.4725 |
| 2014 | | | | |
| High Price | $29.65 | $32.01 | $30.52 | $28.95 |
| Low Price | $18.22 | $27.86 | $25.39 | $22.62 |
| Distribution per common unit | $0.4725 | $0.4725 | $0.4625 | $0.4625 |

As of March 4, 2016, there were 77 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 9,499,370 Series A Units, and 542,002 General Partner units, for which there is no established trading market. 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 units and Series A Units.

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, 2015 and 2014 (in thousands):

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Series A convertible preferred units | 9,210 | 5,745 |
| Series B convertible units (a) | 1,350 | 1,255 |
| Limited partner common units | 30,427 | 22,670 |
| General Partner units | 536 | 392 |

(a) Our General Partner held 1,349,609 Series B convertible units ("Series B Units"), which converted into common units on a one-for-one basis on February 1, 2016.

Our General Partner's initial 2.0% interest in distributions has been reduced to 1.3% 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 notional 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 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.

Series A Distribution Amendment

The Partnership executed an amendment (the "Third Amendment") to the Partnership Agreement related to the outstanding Series A Units which became effective July 24, 2014. As a result of the Third Amendment, distributions on Series A Units can be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the Board of Directors, which began with the distribution for the three months ended June 30, 2014 and will continue through the distribution for the quarter ended March 31, 2016. At December 31, 2015, we had accrued $4.4 million of distributions for the paid-in-kind Series A Units.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2015:

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted-average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 200,000 | $ 7.50 | 15,484 |
| Equity compensation plans not approved by unitholders (a) | — | — | 6,000,000 |
| Total | 200,000 | 7.50 | 6,015,484 |

(a) On November 19, 2015, subject to unitholder approval, the Board of Directors of our General Partner approved the Third Amended and Restated Long-Term Incentive Plan, which, subject to unitholder approval, would increase the number of common units authorized for issuance under the Plan by 6,000,000. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan to increase the number of available awards by 6,000,000 common units. For more information on our Long-Term Incentive Plan, please refer to Item 11. “Executive Compensation,” and Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters - Securities Authorized for Issuance Under Equity Compensation Plans.”

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 and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those consolidated financial statements and notes, which for the years 2015, 2014, and 2013 begin on F-1 to this Annual Report.

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

| | Years ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 (a) | 2014 (a) | 2013 (a) | 2012 | 2011 |
| | (in thousands, except per unit and operating data) | | | | |
| Statements of Operations Data: | | | | | |
| Revenue | $235,034 | $307,309 | $294,051 | $204,868 | $247,043 |
| Realized loss in early termination of commodity derivatives | — | — | — | — | (2,998) |
| Gain (loss) on commodity derivatives, net | 1,324 | 1,091 | 28 | 3,400 | (2,452) |
| Total revenue | 236,358 | 308,400 | 294,079 | 208,268 | 241,593 |
| Operating expenses: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Purchases of natural gas, NGLs and condensate | 105,883 | 197,952 | 215,053 | 154,472 | 200,776 |
| Direct operating expenses | 59,549 | 45,702 | 32,236 | 17,183 | 11,745 |
| Selling, general and administrative expenses | 27,232 | 23,103 | 19,079 | 14,309 | 13,576 |
| Equity compensation expense (b) | 3,774 | 1,536 | 2,094 | 1,783 | 3,357 |
| Depreciation, amortization and accretion expense | 38,014 | 28,832 | 30,002 | 21,287 | 20,454 |
| Total operating expenses | 234,452 | 297,125 | 298,464 | 209,034 | 249,908 |
| 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 | (3,011) | (122) | — | 123 | 399 |
| Loss on impairment of property, plant and equipment | — | (99,892) | (18,155) | — | — |
| Loss of impairment of goodwill | (118,592) | — | — | — | — |
| Operating income (loss) | (119,697) | (88,739) | (22,197) | (1,664) | (7,351) |
| Other income (expense): | | | | | |
| Interest expense | (14,745) | (7,577) | (9,291) | (4,570) | (4,508) |
| Other income (expense) | — | (670) | — | — | — |
| Earnings in unconsolidated affiliates | 8,201 | 348 | — | — | — |
| Net income (loss) before income tax (expense) benefit | (126,241) | (96,638) | (31,488) | (6,234) | (11,859) |
| Income tax (expense) benefit | (1,134) | (557) | 495 | — | — |
| Net income (loss) from continuing operations | (127,375) | (97,195) | (30,993) | (6,234) | (11,859) |
| Discontinued operations: | | | | | |
| Income (loss) from discontinued operations, net of tax | (80) | (611) | (2,413) | (18) | 161 |
| Net income (loss) | (127,455) | (97,806) | (33,406) | (6,252) | (11,698) |
| Net income (loss) attributable to non-controlling interests | 25 | 214 | 633 | 256 | — |
| Net income (loss) attributable to the Partnership | $(127,480) | $(98,020) | $(34,039) | $(6,508) | $(11,698) |
| General Partner's Interest in net income (loss) | $(1,645) | $(1,279) | $(1,405) | $(129) | $(233) |
| Limited Partners' Interest in net income (loss) | $(125,835) | $(96,741) | $(32,634) | $(6,379) | $(11,465) |
| | | | | | |
| Limited Partners' net income (loss) per common unit: | | | | | |
| Basic and diluted: | | | | | |
| Income (loss) from continuing operations | $(6.00) | $(8.54) | $(7.15) | $(0.70) | $(1.66) |
| Income (loss) from discontinued operations | — | (0.04) | (0.27) | — | 0.02 |
| Net income (loss) | $(6.00) | $(8.58) | $(7.42) | $(0.70) | $(1.64) |
| Weighted average number of common units outstanding: | | | | | |
| Basic and diluted (c) | 24,983 | 13,472 | 7,525 | 9,113 | 6,997 |

Statement of Cash Flow Data:
Net cash provided by (used in):

54

| | | | | | |
|---|---|---|---|---|---|
| Operating activities | $40,937 | $21,478 | $17,223 | $18,348 | $10,432 |
| Investing activities | (171,108) | (471,870) | (28,214) | (62,427) | (41,744) |
| Financing activities | 129,672 | 450,490 | 10,816 | 43,784 | 32,120 |
| Other Financial Data: | | | | | |
| Adjusted EBITDA (d) | $66,311 | $45,551 | $31,907 | $18,850 | $20,785 |
| Gross margin (e) | 123,281 | 102,807 | 74,821 | 49,431 | 44,356 |
| Cash distribution declared per common unit | 1.89 | 1.85 | 1.75 | 1.73 | 0.70 |
| Segment gross margin: | | | | | |
| Gathering and Processing | 76,865 | 50,817 | 36,985 | 36,118 | 30,619 |
| Transmission | 35,301 | 42,828 | 32,408 | 13,313 | 13,737 |
| Terminals | 11,115 | 9,162 | 5,428 | — | — |
| Balance Sheet Data (at period end): | | | | | |
| Cash and cash equivalents | $— | $499 | $393 | $576 | $871 |
| Accounts receivable and unbilled revenue | 18,740 | 29,543 | 29,823 | 23,470 | 20,963 |
| Property, plant and equipment, net | 648,013 | 582,182 | 312,701 | 223,819 | 170,231 |
| Total assets | 891,296 | 913,558 | 382,075 | 256,696 | 199,551 |
| Current portion of long-term debt | 2,338 | 2,908 | 2,048 | — | — |
| Long-term debt | 525,100 | 372,950 | 130,735 | 128,285 | 66,270 |
| Operating Data: | | | | | |
| Gathering and processing segment: | | | | | |
| Average throughput (MMcf/d) | 338.2 | 274.8 | 277.2 | 291.2 | 250.9 |
| Average plant inlet volume (MMcf/d) (e) | 120.9 | 89.1 | 117.3 | 116.1 | 36.7 |
| Average gross NGL production (Mgal/d)(e) | 231.1 | 64.2 | 52.0 | 49.9 | 54.5 |
| Average gross condensate production (Mgal/d) (f) | 99.8 | 75.2 | 46.2 | 22.6 | 22.6 |
| Transmission segment: | | | | | |
| Average throughput (MMcf/d) | 708.6 | 778.9 | 644.7 | 398.5 | 381.1 |
| Average firm transportation - capacity reservation (MMcf/d) | 653.7 | 577.9 | 640.7 | 703.6 | 702.2 |
| Average interruptible transportation - throughput (MMcf/d) | 410.3 | 468.9 | 389.2 | 86.6 | 69.0 |
| Terminals segment: | | | | | |
| Storage utilization | 88.1 % | 91.4 % | 95.6 % | — | — |

(a) During these years, we had the following transactions that affect comparability: i) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House, which we account for as an equity method investment; ii) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gathering and Processing segment; iii) in December 2013, we acquired Blackwater, which is included in our Terminals segment; and iv) in April 2013, we acquired the High point System, which is included in Transmission segment.

(b) Represents cash and non-cash costs related to our Long-Term Incentive Plans. Of these amounts, $1.6 million were cash expenses for the year ended December 31, 2011.

(c) Includes unvested phantom units with distribution equivalent rights ("DERs), which are considered participating securities, of 200,000 at December 31, 2015.

(d)

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 "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations."

(e) 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 "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations."

(f) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read "Item 7. Management's Discussion and Analysis — Our Operations - Gathering and Processing Segment"

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 Annual Report. 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 About 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, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products, all through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three marine terminal sites, three interstate pipelines, five intrastate pipelines and one crude oil pipeline. We also own a 66.7% non-operated interest in Main Pass Oil Gathering Company ("MPOG"), a crude oil gathering and processing system; a 50% undivided, non-operated interest in the Burns Point Plant, a natural gas processing plant; a 46% non-operated interest in Mesquite, an off-spec condensate fractionation project; and, a 12.9% non-operated indirect interest in Delta House, a floating production system platform and related pipeline infrastructure. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas, and the Gulf of Mexico, provide critical infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate approximately 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.8 million barrels of storage capacity across three marine terminal sites.

Significant financial highlights during the year ended December 31, 2015, include the following:

- Gross margin increased to $123.3 million, or an increase of 19.9%, as compared to the same period in 2014 primarily due to the Costar and Lavaca acquisitions in October 2014 and January 2014, respectively;

- Adjusted EBITDA increased to $66.3 million, or an increase of 45.4%, as compared to the same period in 2014 primarily due to the Costar and Lavaca acquisitions, as well as distributions from Delta House;

- We distributed $46.6 million to our Limited Partner common unitholders, or $1.89 per unit;

- On September 15, 2015, we issued 7,500,000 common units at a price of $11.31 per common unit and received $81.0 million in net proceeds which were used to fund a portion of our investment in Delta House;

- On September 18, 2015, we entered into the First Amendment and Incremental Commitment Agreement to our Amended and Restated Credit Agreement dated as of September 5, 2014 (as amended, the Credit Agreement), which increased our borrowing capacity from $500.0 million to $750.0 million, with the ability to further increase the borrowing capacity subject to lender approval; and

- 

On September 18, 2015, an affiliate of our General Partner contributed a 12.9% indirect interest in Delta House to the Partnership in exchange for consideration of $162.0 million.

Significant operational highlights during the year ended December 31, 2015, include the following:

- The percentage of gross margin generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts increased to 85.8% compared to 74.4% for 2014;
- Average gross NGL production totaled 231.1 Mgal/d, representing a 166.9 Mgal/d or 260.0% increase compared to 2014;
- Average gross condensate production totaled 99.8 Mgal/d, representing a 24.6 Mgal/d or 32.7% increase compared to 2014;

- Throughput volumes attributable to the Partnership totaled 1,046.8 MMcf/d, which is consistent with 2014; and
- Contracted capacity for our Terminals segment averaged 1,487,542 barrels, representing a 19.3% increase compared to 2014.

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 crude oil, which include transporting raw natural gas and crude oil 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, crude oil, and NGLs to various markets and pipeline systems.
- Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include local distribution companies ("LDCs"), utilities and industrial, commercial and power generation customers.
- Terminals. Our Terminals segment provides above-ground leasable storage operations at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products.

Gathering and Processing Segment

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

- Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed fee for gathering, processing and transporting natural gas and crude oil.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas and off-spec condensate 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 or off-spec condensate at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas or off-spec condensate, 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, 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. Our POP arrangements also often contain a fee-based component.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas and crude oil 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 throughput volumes from producers 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 "Item 7A — 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

Our Terminals segment provides above-ground leasable 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 petroleum products, distillates, chemicals and agricultural products. We generally receive fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed and other fee-based charges associated with ancillary services provided to our customers, such as excess throughput, truck weighing, etc. Our firm storage contracts are typically multi-year contracts with renewal options.

Contract Mix

For the years ended December 31, 2015, 2014, and 2013, $105.8 million, $76.6 million, and $48.7 million, or 85.8%, 74.4%, and 65.1%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts. Set forth below is a table summarizing our average contract mix relative to segment gross margin for the years ended December 31, 2015, 2014, and 2013 (in thousands):

| | For the Year Ended December 31, 2015 | | | For the Year Ended December 31, 2014 | | | For the Year Ended December 31, 2013 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Segment Gross Margin | Percent of Segment Gross Margin | | Segment Gross Margin | Percent of Segment Gross Margin | | Segment Gross Margin | Percent of Segment Gross Margin | |
| Gathering and Processing | | | | | | | | | |
| Fee-based | $40,278 | 52.4 | % | $21,394 | 42.1 | % | $8,876 | 24.0 | % |
| Fixed margin | 19,139 | 24.9 | % | 3,151 | 6.2 | % | 1,997 | 5.4 | % |
| Percent-of-proceeds | 17,448 | 22.7 | % | 26,272 | 51.7 | % | 26,112 | 70.6 | % |
| Total | $76,865 | 100.0 | % | $50,817 | 100.0 | % | $36,985 | 100.0 | % |
| Transmission | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Firm transportation | $10,767 | 30.5 | % | $11,092 | 25.9 | % | $10,597 | 32.7 | % |
| Interruptible transportation | 24,534 | 69.5 | % | 31,736 | 74.1 | % | 21,714 | 67.0 | % |
| Fixed margin | — | — | % | — | — | % | 97 | 0.3 | % |
| Total | $35,301 | 100.0 | % | $42,828 | 100.0 | % | $32,408 | 100.0 | % |
| Terminals | | | | | | | | | |
| Firm storage | $11,115 | 100.0 | % | $9,162 | 100.0 | % | $5,428 | 100.0 | % |
| Total | $11,115 | 100.0 | % | $9,162 | 100.0 | % | $5,428 | 100.0 | % |

Cash distributions derived from our unconsolidated affiliates amounted to $20.6 million and $2.0 million for the years ended December 31, 2015 and 2014, respectively, and are primarily generated from fee-based gathering and processing arrangements.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and 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, crude oil, NGLs and condensate to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes and obtain new supplies of natural gas, crude oil, NGLs and condensate is impacted by i) the level of work-overs or recompletions of existing connected wells and successful drilling activity of our significant producers 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, crude oil, NGLs and condensate that has been released from other commitments and iv) the volume of crude oil, natural gas, NGLs and condensate that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to maintain current throughput volumes or pursue new supply opportunities.

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines. Substantially all of our 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 maintain current throughput volumes or pursue new shipper opportunities.

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

Storage Utilization

Storage utilization is a metric that we use to evaluate the performance of our Terminals segment. We define storage utilization as the percentage of the contracted capacity in barrels compared to the design capacity of the tank.

Segment Gross Margin and Gross Margin

Segment gross margin and 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 and realized gains or (losses) on commodity derivatives, less the cost of natural gas, crude oil, NGLs and condensate purchased and revenue from construction, operating and maintenance agreements ("COMA"). Revenue includes revenue generated from fixed fees associated with the gathering and treatment of natural gas and crude oil and from the sale of natural gas, crude oil, 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 directly comparable to gross margin is net income (loss) attributable to the Partnership.

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 flow from operations to make cash distributions to our unit holders and General Partner and its affiliates;
- 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 (loss) attributable to the Partnership, plus interest expense, income tax expense, depreciation, amortization and accretion expense, certain non-cash charges such as non-cash equity compensation expense, unrealized losses on commodity derivative contracts, debt issuance costs, return of capital from unconsolidated affiliates, transaction expenses and selected charges that are unusual or nonrecurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, and selected gains that are unusual or nonrecurring. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to the Partnership.

Note About Non-GAAP Financial Measures

Gross margin, segment gross margin and Adjusted EBITDA are performance measures that are considered 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 gross margin, segment 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 in our industry.

The following tables reconcile the non-GAAP financial measures of gross margin and Adjusted EBITDA used by management to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for each of the three years ended December 31, 2015, 2014 and 2013 (in thousands):

60

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 (a) | 2014 (a) | 2013 (a) |
| Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership | | | |
| Gathering and processing segment gross margin | $ 76,865 | $ 50,817 | $ 36,985 |
| Transmission segment gross margin | 35,301 | 42,828 | 32,408 |
| Terminals segment gross margin (b) | 11,115 | 9,162 | 5,428 |
| Total gross margin | 123,281 | 102,807 | 74,821 |
| Plus: | | | |
| Gain (loss) on commodity derivatives, net | 1,324 | 1,091 | 28 |
| Earnings in unconsolidated affiliates | 8,201 | 348 | — |
| Less: | | | |
| Direct operating expenses (b) | 52,909 | 39,360 | 27,833 |
| Selling, general and administrative expenses | 27,232 | 23,103 | 19,079 |
| Equity compensation expense | 3,774 | 1,536 | 2,094 |
| Depreciation, amortization and accretion expense | 38,014 | 28,832 | 30,002 |
| (Gain) loss on involuntary conversion of property, plant and equipment | — | — | (343) |
| (Gain) loss on sale of assets, net | 3,011 | 122 | — |
| Loss on impairment of property, plant and equipment | — | 99,892 | 18,155 |
| Loss on impairment of goodwill | 118,592 | — | — |
| Interest expense | 14,745 | 7,577 | 9,291 |
| Other (income) expense | — | 670 | — |
| Other, net (c) | 770 | (208) | 226 |
| Income tax expense (benefit) | 1,134 | 557 | (495) |
| Income (loss) from discontinued operations, net of tax | 80 | 611 | 2,413 |
| Net income (loss) attributable to noncontrolling interest | 25 | 214 | 633 |
| Net income (loss) attributable to the Partnership | $ (127,480) | $ (98,020) | $ (34,039) |

(a) During these years, we had the following transactions that affect comparability: i) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House, which we account for as an equity method investment; ii) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gathering and Processing segment; iii) in December 2013, we acquired Blackwater, which is included in our Terminals segment; and iv) in April 2013, we acquired the High Point System, which is included in our Transmission segment.

(b) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $39.2 million, $23.8 million, and $14.6 million and Transmission segment direct operating expenses of $13.7 million, $15.6 million, and $13.3 million for each of the three years ended December 31, 2015, 2014 and 2013, respectively. Direct operating expenses related to our Terminals segment of $6.6 million, $6.3 million, and $4.4 million are included within the calculation of Terminals segment gross margin for each of the three years ended December 31, 2015, 2014 and 2013, respectively.

(c) Other, net includes realized gain on commodity derivatives of $1.6 million, $0.7 million and $1.1 million and COMA income of $0.8 million, $0.9 million and $0.8 million for each of the years ended December 31, 2015, 2014 and 2013, respectively.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Reconciliation of Adjusted EBITDA to Net income (loss) attributable to the Partnership | | | |
| Net income (loss) attributable to the Partnership | $(127,480) | $(98,020) | $(34,039) |
| Add: | | | |
| Depreciation, amortization and accretion expense | 38,014 | 28,832 | 30,002 |
| Interest expense | 13,631 | 6,433 | 7,850 |
| Debt issuance costs | 2,238 | 3,841 | 2,113 |
| Unrealized (gain) loss on derivatives, net | 71 | (595) | 1,495 |
| Non-cash equity compensation expense | 3,863 | 1,626 | 2,094 |
| Transaction expenses | 1,426 | 1,794 | 3,987 |
| Income tax expense (benefit) | 953 | 224 | (847) |
| Impairment on property, plant and equipment | — | 99,892 | 18,155 |
| Loss on impairment of noncurrent assets held for sale | — | 673 | 2,400 |
| Loss on impairment of goodwill | 118,592 | — | — |
| Proceeds from equity method investment, return of capital | 12,367 | 1,632 | — |
| General Partner contribution for cost reimbursement | 330 | — | — |
| Deduct: | | | |
| COMA income | 841 | 943 | 843 |
| Straight-line amortization of put costs | — | — | 119 |
| OPEB plan net periodic benefit | 14 | 45 | 73 |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | — | 343 |
| Gain (loss) on sale of assets, net | (3,161) | (207) | (75) |
| Adjusted EBITDA | $66,311 | $45,551 | $31,907 |

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 September 18, 2015, we acquired a 12.9% non-operated indirect interest in Delta House, which is a floating production system platform with associated crude oil and natural gas export pipelines, for a net purchase price of $162.0 million. The investment was financed by proceeds of a public offering of 7.5 million of the Partnership's common units and through borrowings under the Partnership's Credit Agreement. The interest is accounted for as an equity method investment under ASC 323, Investments-Equity Method and Joint Ventures.
- On October 14, 2014, we acquired Costar from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC for approximately $405.3 million.
- On August 11, 2014, we acquired a 66.7% non-operated interest in MPOG, which is an offshore crude oil gathering system, for a net purchase price of $12.0 million. The acquisition was financed through borrowings under the Partnership's Credit Agreement. The interest is accounted for as an equity method investment under ASC 323, Investments-Equity Method and Joint Ventures.
- On January 31, 2014, we acquired our Lavaca System, which is an onshore gas gathering system for approximately $104.4 million.
- On April 15, 2013, our General Partner contributed the High Point System.
- On December 17, 2013, we completed the acquisition of Blackwater from our General Partner. The net assets received were recorded at their historical book value of $22.7 million as of the date common control was established, which was April 15, 2013; and

- During the fourth quarter of 2013, we acquired an additional 4.8% undivided interest in the Chatom System, increasing our ownership to 92.2%.

General Trends and Outlook

During 2016, our business objectives will continue to focus on maintaining stable cash flows from our existing assets and executing on growth opportunities to increase our long-term cash flows. We believe the key elements to stable cash flows are the diversity of our asset portfolio and our fee-based business which represents a significant portion of our estimated margins, the objective of which is to protect against downside risk in our cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $5.5 million and $6.5 million, and approved expenditures for expansion capital of between $45.0 million and $55.0 million, for the year ending December 31, 2016. Forecasted growth capital expenditures include construction of midstream infrastructure for the Permian Off-spec treating facility, expansion of the Harvey terminal, continued build-out of Lavaca System, completion of the Longview Rail and Yellow Rose facilities, and other organic growth projects.

We expect to continue to pursue a multi-faceted growth strategy, which includes maximizing drop down opportunities provided by our relationship with ArcLight, capitalizing on organic expansion and pursuing strategic third-party acquisitions in order to grow our cash flows. However, in light of the sharp decline in energy commodity prices that began in fourth quarter of 2014 and continued throughout 2015, we expect producer and supplier activities to be impacted, which may reduce the growth rate of our Gathering and Processing and Transmission segments.

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.

Gathering and Processing Segment. Except for our fee-based contracts, which may be impacted by throughput volumes, the profitability of our gathering and processing segment is dependent upon commodity prices, natural gas and crude oil supply, and demand for natural gas, crude oil, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile and saw a significant decline in the latter part of 2014 and continued throughout 2015. Throughput volumes could decline, particularly in areas with lower NGL content, should commodity prices and drilling levels continue to experience weakness.

Transmission Segment. Profitability of our transmission segment is dependent upon the demand to transport natural gas pursuant to our firm and interruptible transportation contracts. Throughput volumes could continue to decline should natural gas prices and drilling levels continue to experience weakness as a result of volatile commodity prices.

Terminals Segment. Profitability of our terminals segment is dependent upon the demand from our customers to store their products, which is generally not tied to the crude oil and natural gas commodity markets. Currently, we have not experienced deterioration of terminal gross margin in connection with the volatility of the natural gas, crude oil, NGL or condensate markets. Further, the terms of our firm storage contracts are multiple years, with renewal options.

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.43 per barrel to a low of $26.21 per barrel from January 1, 2015 through March 1, 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.23 per MMBtu to a low of $1.71 per MMBtu from January 1, 2015 through March 1, 2016. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices continue to trend lower as they did in the latter part of 2014 and through early 2016, this could lead to reduced profitability and may impact our liquidity, compliance with financial covenants in our Credit Agreement, and our ability to maintain our current distribution levels. Our long-term view is that as economic conditions improve, commodity prices should reach levels that will support continued natural gas and crude oil production in the United States. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

On January 25, 2016, we announced that the Board of Directors of our General Partner voted to maintain our quarterly cash distribution of $0.4725 per unit for the fourth quarter ended December 31, 2015, or $1.89 per unit on an annualized basis. The cash distribution was paid on February 12, 2016, to unitholders of record as of the close of business on February 3, 2016. The amount of our cash distributions on our units principally depends upon the amount of cash we generate from our operations, which could be adversely impacted by market conditions and factors outside of our control. The Partnership Agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations.

Capital Markets. Volatility in the capital markets may impact our operations in multiple ways, including limiting our producers' ability to finance their drilling and workover programs and limiting our ability to fund drop downs, organic growth projects and acquisitions.

Impact of Inflation on Direct Operating Expenses. Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our operations fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high-energy commodity prices.

Results of Operations — Combined Overview

Gross margin increased by $20.5 million, or 19.9%, for the year ended to December 31, 2015 to $123.3 million as compared to the same period in 2014. For the year ended December 31, 2015, the increase in gross margin was largely a result of incremental segment gross margin of $24.2 million associated with the gathering and processing systems obtained through the Costar acquisition in October 2014 and higher gross margin of $4.8 million was attributable to the Lavaca System acquisition in January 2014; which was partially offset by lower gross margin in our Transmission segment of $7.5 million as a result of a decrease in average throughput volumes and changes in pipeline imbalances.

For the year ended December 31, 2015, Adjusted EBITDA increased $20.7 million, or 45.4%, compared to the same period in 2014. The increase is primarily related to incremental segment gross margin in the Gathering and Processing segment from the Costar acquisition, higher gross margin related to the Lavaca System acquisition, and higher cash distributions derived from our unconsolidated affiliates of $18.6 million due to the September 2015 investment in Delta House. These increases were partially offset by higher direct operating expenses associated with the Costar and Lavaca System acquisitions and lower gross margin in our Transmission segment.

We distributed $46.6 million to holders of our common units, or $1.89 per unit, during the year ended December 31, 2015, including the distribution with respect to the three months ended December 31, 2014. The distribution of $1.89 per unit represents a 2% increase in annual distributions, period over period.

The following table and discussion presents certain of our historical consolidated financial data for the periods indicated.

The results of operations by segment are discussed in further detail following this combined overview (in thousands):

| | For the Years Ended December 31, 2015 | 2014 | 2013 |
|---|---|---|---|
| Statements of Operations Data: | | | |
| Revenue | $235,034 | $307,309 | $294,051 |
| Gain (loss) on commodity derivatives | 1,324 | 1,091 | 28 |
| Total revenue | 236,358 | 308,400 | 294,079 |
| Operating expenses: | | | |
| Purchases of natural gas, NGLs and condensate | 105,883 | 197,952 | 215,053 |
| Direct operating expenses | 59,549 | 45,702 | 32,236 |
| Selling, general and administrative expenses | 27,232 | 23,103 | 19,079 |
| Equity compensation expense (a) | 3,774 | 1,536 | 2,094 |
| Depreciation, amortization and accretion expense | 38,014 | 28,832 | 30,002 |
| Total operating expenses | 234,452 | 297,125 | 298,464 |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | — | 343 |
| Gain (loss) on sale of assets, net | (3,011) | (122) | — |
| Loss on impairment of property, plant and equipment | — | (99,892) | (18,155) |
| Loss on impairment of goodwill | (118,592) | — | — |
| Operating income (loss) | (119,697) | (88,739) | (22,197) |
| Other income (expenses): | | | |
| Interest expense | (14,745) | (7,577) | (9,291) |
| Other income (expense) | — | (670) | — |
| Earnings in unconsolidated affiliates | 8,201 | 348 | — |
| Net income (loss) before income tax (expense) benefit | (126,241) | (96,638) | (31,488) |
| Income tax (expense) benefit | (1,134) | (557) | 495 |
| Net income (loss) from continuing operations | (127,375) | (97,195) | (30,993) |
| Discontinued operations: | | | |
| Income (loss) from discontinued operations, net of tax | (80) | (611) | (2,413) |
| Net income (loss) | (127,455) | (97,806) | (33,406) |
| Net income (loss) attributable to noncontrolling interests | 25 | 214 | 633 |
| Net income (loss) attributable to the Partnership | $(127,480) | $(98,020) | $(34,039) |
| | | | |
| Other Financial Data: | | | |
| Gross margin (b) | $123,281 | $102,807 | $74,821 |
| Adjusted EBITDA (b) | $66,311 | $45,551 | $31,907 |

(a) Primarily represents non-cash costs related to our Long-Term Incentive Plans.

(b) For definitions of gross margin and Adjusted EBITDA and reconciliations to their most directly comparable financial measure calculated and presented in accordance with GAAP, and a discussion of how we use gross margin and Adjusted EBITDA to evaluate our operating performance, please read the information in this Item under the caption "— How We Evaluate Our Operations."

Year ended December 31, 2015, compared to year ended December 31, 2014

Revenue. Our total revenue for the year ended December 31, 2015 was $236.4 million compared to $308.4 million for the year ended December 31, 2014. This decrease of $72.0 million was primarily due to a decrease in natural gas and condensate revenues of $95.2 million and $11.0 million, respectively. These decreases were primarily as a result of:

- lower realized natural gas prices of $2.91/Mcf, which is a decrease of $2.01/Mcf, or 40.9%, period over period,

- lower realized condensate prices of $0.97/gal, which is a decrease of $0.65/gal, or 40.1%, period over period, offset by higher gross condensate production volumes of 24.6 Mgal/d, or 32.7%, period over period, from our Gathering and Processing segment,
- converting fixed-margin contracts in our transmission segment to firm or interruptible transportation contracts, and
- lower throughput volumes associated with our elective processing arrangements.

The decrease in natural gas and condensate revenues was partially offset by:

- an increase in NGL revenues of $15.5 million as a result of higher gross NGL production volumes of 166.9 Mgal/d from our Gathering and Processing segment, which was offset by lower realized NGL prices of $0.58/gal, which is a decrease of $0.33/gal., period over period,
- an increase in fee-based revenue of $19.0 million primarily due to increased average throughput volumes in our Gathering and Processing segment of 63.4 MMcf/day, or 23.1%, and
- an increase in the Terminals segment revenue of $2.3 million as a result of increased storage utilization from acquiring new customers and contractual storage rate escalations.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2015, were $105.9 million compared to $198.0 million in the year ended December 31, 2014. This decrease of $92.1 million was due to lower natural gas purchases of $94.3 million primarily as a result of lower natural gas prices and lower natural gas volumes related to our elective processing arrangements in our Gathering and Processing segment, as well as the conversion of certain fixed-margin contracts to interruptible transportation contracts in our Transmission segment as mentioned above.

This decrease was partially offset by incremental NGL, crude oil and condensate purchases of $2.2 million primarily associated with the gathering and processing systems acquired in the Costar Acquisition.

Gross Margin. Gross margin for the year ended December 31, 2015, was $123.3 million compared to $102.8 million for the year ended December 31, 2014. This increase of $20.5 million was primarily due to an increase in segment gross margin in our Gathering and Processing segment of $26.0 million as a result of higher NGL and condensate production of 166.9 Mgal/d and 24.6 Mgal/d, respectively, and higher throughput volumes of 63.4 MMcf/d, as well as higher segment gross margin in our Terminals segment of $2.0 million. These increases were partially offset by lower segment gross margin in our Transmission segment of $7.5 million as a result of a decrease in average throughput volumes.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015, were $59.5 million compared to $45.7 million for the year ended December 31, 2014. This increase of $13.8 million was primarily due to $13.4 million of incremental operating costs, including costs related to direct labor and benefits, associated with the gathering and processing systems acquired from Costar, and an increase of $2.1 million in operating costs associated with compression rentals used at our Lavaca System. These increases were partially offset by the timing of activities related to our integrity management and plant repair and maintenance programs.

Selling, General and Administrative ("SG&A") Expenses. SG&A expenses for the year ended December 31, 2015, were $27.2 million compared to $23.1 million for the year ended December 31, 2014. This increase of $4.1 million was primarily due to personnel costs incurred to manage and integrate our recent acquisitions and support continuing growth.

Equity Compensation Expense. Equity compensation expense related to our Long-Term Incentive Plan for the year ended December 31, 2015, was $3.8 million compared to $1.5 million for the year ended December 31, 2014. This increase of $2.3 million was primarily due to a one-time award made to certain executives in lieu of cash payments related to our short-term incentive compensation plan during the current year.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the year ended December 31, 2015, was $38.0 million compared to $28.8 million for the year ended December 31, 2014. This increase of $9.2 million was primarily due to incremental depreciation of fixed assets and amortization of certain intangible assets associated with the Costar Acquisition and the continuing capital expansion of the Lavaca System.

Loss on Impairment of Property, Plant and Equipment. During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil led to a corresponding decrease in natural gas and crude oil production and impacted the throughput volume of natural and NGLs we gather and process on certain assets. As a result, asset impairment charges of $99.9 million related to certain legacy gathering and processing assets were recorded during the fourth quarter of 2014.

Loss on Impairment of Goodwill. During the fourth quarter of 2015, management performed the Partnership's annual goodwill impairment test. As a result of the continuing decline in commodity prices, as well as the decline in the market price for the Partnership's common units during the fourth quarter, key assumptions relating to expected producer volumes and commodity prices used in management's impairment testing cash flow models were updated. The updated assumptions resulted in the estimated fair value of the Costar and Lavaca reporting units being less than their respective carrying values, indicating that the related goodwill was impaired. After completing an allocation of the estimated fair value of each reporting unit to the associated assets and liabilities, management determined that the goodwill of the Costar and Lavaca reporting units had a nominal fair value and that impairment charges of $118.6 million were required. Such impairment charges were recorded during the fourth quarter of 2015.

Interest Expense. Interest expense for the year ended December 31, 2015, was $14.7 million compared to $7.6 million for the year ended December 31, 2014. This increase of $7.1 million was primarily due to higher outstanding borrowings under the Credit Agreement to fund our capital growth projects and the Costar acquisition and Delta House Investment.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2015 were $8.2 million compared to $0.3 million for the year ended December 31, 2014. This increase of $7.9 million was due to incremental earnings of $7.5 million related to Delta House, and higher earnings from MPOG of $0.4 million.

Year ended December 31, 2014, compared to year ended December 31, 2013

Revenue. Our revenue for the year ended December 31, 2014 was $307.3 million compared to $294.1 million for the year ended December 31, 2013. This increase of $13.2 million was primarily due to:

- an increase in natural gas revenues of $9.3 million as a result of higher realized natural gas prices of $4.92/Mcf, an increase of $0.89/Mcf, or 22.1%, period over period;
- an increase in NGL revenues of $0.3 million as a result of higher gross NGL production volumes of 12.2 Mgal/d from our Gathering and Processing segment and higher realized NGL prices of $0.91/gal, an increase of $0.01/gal period over period;
- an increase in transmission revenues from the transportation of natural gas increased $9.1 million, or 11.6%, primarily due to an increase in throughput of 134.2 MMcf/d as a result of the benefit of twelve months of revenue from the High Point System in 2014, compared to less than nine months in 2013; and
- an increase in Terminals segment revenue of $5.7 million primarily due to higher contracted storage capacity and auxiliary services as well as having the benefit of twelve months of revenue from Terminals in 2014 compared to less than nine months in 2013.

These increases were partially offset by a decrease in condensate revenues of $9.0 million as a result of lower realized condensate prices of $1.62/gal, a decrease of $0.67/gal period over period, partially offset by higher condensate production of 29.0 Mgal/d.

Gain on Commodity Derivatives, Net. Gain on commodity derivatives, net presents our commodity derivatives which were comprised of financial swaps, collars and option contracts used to mitigate commodity price risk that have settled in 2014 or will be settled in 2015. The value of these derivatives increased by $1.1 million due to declining commodity prices. For a discussion of our commodity derivative positions, please read "Item 7a. Quantitative and Qualitative Disclosures about Market Risk."

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2014 were $198.0 million compared to $215.1 million in the year ended December 31, 2013.

This decrease of $17.1 million was primarily due to lower natural gas purchase volumes associated with our fixed-margin contracts and realized condensate prices, partially offset by higher purchase costs associated with NGL and condensate production and higher realized natural gas prices related to POP contracts associated with owned processing plants.

Gross Margin. Gross margin for the year ended December 31, 2014 was $102.8 million compared to $74.8 million for the year ended December 31, 2013. This increase of $28.0 million was primarily due to: i) an increase in gross margin in our Transmission segment of $10.4 million as a result of increased throughput of 134.2 MMcf/d primarily as a result of twelve months of activity on our High Point Systems in 2014 compared to less than nine months of activity in 2013; ii) an increase in our Terminals segment of $3.7 million due to incremental storage capacity and associated customers as well as twelve months of activity in 2014 compared to less than nine months of activity in 2013; and iii) an increase in gross margin in our Gathering and Processing segment of $13.8 million due to $16.5 million attributable to the acquired Lavaca System and incremental gross margin of $8.0 million attributable to the assets acquired from Costar, partially offset by declines in gross margin at our other gathering and processing assets together with lower realized condensate prices of $0.67, or 29.3%, period over period.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014 were $45.7 million compared to $32.2 million in the year ended December 31, 2013. This increase of $13.5 million was primarily due to: i) $3.4 million of incremental operating expenses associated with the Costar acquisition; ii) $2.0 million of additional material and supplies associated with our Terminal segment; iii) $3.3 million of incremental costs associated with compression rentals; iv) $1.0 million of costs associated with additional pipeline inspections; v) higher salaries, wages and related costs of $1.2 million associated with new personnel additions incurred to manage and integrate our acquisitions and support our continued growth; and vi) $0.8 million associated with integrity management programs.

Selling, General and Administrative Expenses. SG&A expenses for the year ended December 31, 2014 were $23.1 million compared to $19.1 million for the year ended December 31, 2013. This increase of $4.0 million was primarily due to: i) higher salaries, wages and related costs of $3.4 million associated with personnel additions incurred to manage and integrate our acquisitions and support our continued growth; ii) an increase in legal fees of $0.9 million associated with certain transactions; and iii) $0.5 million of incremental SG&A associated with the Costar acquisition.

Equity Compensation Expense. Compensation expense related to our LTIP for the year ended December 31, 2014 was $1.5 million compared to $2.1 million for the year ended December 31, 2013. This decrease of $0.6 million was primarily due to a one-time grant award made in 2013 associated with the acquisition of the High Point System that did not occur in 2014.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the year ended December 31, 2014 was $28.8 million compared to $30.0 million for the year ended December 31, 2013. This decrease of $1.2 million was primarily due to i) $6.8 million of incremental depreciation of assets associated with acquisitions; and ii) $1.4 million of incremental amortization of intangible assets; which was partially offset by $9.2 million of a reduction in depreciation of certain assets becoming fully depreciated in the current period.

Loss on Impairment of Property, Plant and Equipment. During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil has led to a corresponding decrease in crude oil and natural gas production and is impacting the volume of natural and NGLs we gather and process on certain assets. As a result, asset impairment charges of $99.9 million related to certain gathering and processing assets were recorded during the fourth quarter of 2014.

Interest Expense. Interest expense for the year ended December 31, 2014, was $7.6 million compared to $9.3 million for the year ended December 31, 2013. This decrease of $1.7 million was primarily due to i) a lower outstanding debt balance under the Credit Agreement and ii) a slight decrease to our weighted average interest rate of 0.73% as a result of lower leverage during the year ended December 31, 2014.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates of $0.3 million represents our 66.7% share of earnings from MPOG for the year ended December 31, 2014 which was acquired in August 2014.

Results of Operations — Segment Results

Gathering and Processing Segment

The table below contains key segment performance indicators related to our Gathering and Processing segment (in thousands except operating and pricing data).

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Segment Financial and Operating Data: | | | |
| Gathering and Processing segment | | | |
| Financial data: | | | |
| Revenue | $173,597 | $203,616 | $205,179 |
| Gain (loss) on commodity derivatives, net | 1,324 | 1,091 | 28 |
| Total revenue | 174,921 | 204,707 | 205,207 |
| Purchases of natural gas, NGLs and condensate | 97,580 | 152,690 | 168,574 |
| Direct operating expenses | 39,189 | 23,783 | 14,574 |
| Other financial data: | | | |
| Segment gross margin | $76,865 | $50,817 | $36,985 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 338.2 | 274.8 | 277.2 |
| Average plant inlet volume (MMcf/d) (a) | 120.9 | 89.1 | 117.3 |
| Average gross NGL production (Mgal/d) (a) | 231.1 | 64.2 | 52.0 |
| Average gross condensate production (Mgal/d) (a) | 99.8 | 75.2 | 46.2 |
| Average realized prices: | | | |
| Natural gas ($/Mcf) | $2.91 | $4.92 | $4.03 |
| NGLs ($/gal) | $0.58 | $0.91 | $0.90 |
| Condensate ($/gal) | $0.97 | $1.62 | $2.29 |

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

Year Ended December 31, 2015, Compared to Year Ended December 31, 2014

Revenue. Segment total revenue for the year ended December 31, 2015 was $174.9 million compared to $204.7 million for the year ended December 31, 2014. This decrease of $29.8 million was primarily due to lower realized natural gas, NGL and condensate prices of 40.9%, 36.3%, and 40.1%, respectively.

These decreases were partially offset by higher average throughput volumes of 63.4 MMcf/d, and higher average NGL and condensate production of 166.9 Mgal/d and 24.6 Mgal/d, respectively. The increase in average throughput volumes is primarily due to incremental average throughput volumes associated with the gathering and processing systems related to the Costar and Lavaca System acquisitions.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2015 were $97.6 million compared to $152.7 million for the year ended December 31, 2014. This decrease of $55.1 million was primarily due to lower purchase costs associated with natural gas and NGLs, period over period, due to lower realized natural gas and NGL prices and lower natural gas volumes associated with our elective processing arrangements. These decreases were partially offset by incremental purchases associated with off-spec NGL and condensate throughput volumes related to the Longview System.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015 was $76.9 million compared to $50.8 million for the year ended December 31, 2014. This increase of $26.1 million was primarily due to incremental gross margin of $24.2 million related to the Longview, Chapel Hill, Danville, Yellow Rose, and Bakken Systems and higher gross margin of $4.8 million at our Lavaca System. These increases were partially offset by lower NGL and condensate production associated with our elective processing arrangements.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015 were $39.2 million compared to $23.8 million for the year ended December 31, 2014. This increase of $15.4 million was primarily due to the incremental operating costs associated with the gathering and processing systems acquired in the Costar and Lavaca acquisitions, partially offset by the timing of activities related to our integrity management and plant repair and maintenance programs.

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

Revenue. Segment revenue for the year ended December 31, 2014, was $204.7 million compared to $205.2 million for the year ended December 31, 2013. This decrease of $0.5 million was primarily due to lower average natural gas throughput volumes of 2.4 MMcf/d, or 0.9%, period over period, as a result of reduced volumes associated with fixed-margin and POP contracts at certain legacy gathering and processing systems and lower realized condensate prices of $0.67, or 29.3%.

These decreases were offset by higher realized natural gas prices of $0.89, or 22.1%; higher average gross condensate production of 29.0 Mgal/d, or a net increase of 62.8%, primarily as a result of condensate production at our Lavaca System; and higher average gross NGL production amounting to 12.2 Mgal/d, or a net increase of 23.5%, primarily as a result of NGL production at our Longview and Chapel Hill Systems, partially offset by reduced production at certain legacy gathering and processing systems and lower NGL volume associated with our elective processing arrangements.

Gain on Commodity Derivatives, Net. Gain 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 settled in 2014 or 2015 increased $1.1 million period over period due to holding net short positions in a declining commodity price market. For a discussion of our commodity derivative positions, please read "Item 7A. 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, 2014, were $152.7 million compared to $168.6 million for the year ended December 31, 2013. This decrease of $15.9 million was primarily due to lower natural gas purchase volumes associated with our fixed-margin contracts and realized condensate prices, offset by higher purchase costs associated with NGL and condensate production and higher realized natural gas prices related to fixed-margin and POP contracts associated with owned processing plants.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014, was $50.8 million compared to $37.0 million for the year ended December 31, 2013. This increase of $13.8 million was primarily due to incremental gross margin of $16.5 million at our Lavaca System and incremental gross margin of $8.0 million at our Longview, Chapel Hill and Yellow Rose Systems. These increases were partially offset by lower gross margin of $4.6 million due to lower average gross NGL production associated with our elective processing arrangements on our Gloria and Lafitte Systems; as well as lower plant inlet volumes and corresponding NGL sales associated with certain legacy gathering and processing systems of $5.0 million.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $23.8 million compared to $14.6 million for the year ended December 31, 2013. This increase of $9.2 million was primarily due to the incremental operating costs associated with our newly acquired Lavaca System and the gathering and processing assets of Costar.

Transmission Segment

The table below contains key segment performance indicators related to our Transmission segment (in thousands except operating and pricing data).

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Segment Financial and Operating Data: | | | |

| | | | |
|---|---|---|---|
| Transmission segment | | | |
| Financial data: | | | |
| Revenue | $43,682 | $88,189 | $79,041 |
| Purchases of natural gas, NGLs and condensate | 8,303 | 45,262 | 46,479 |
| Direct operating expenses | 13,720 | 15,577 | 13,259 |
| Other financial data: | | | |
| Segment gross margin | $35,301 | $42,828 | $32,408 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 708.6 | 778.9 | 644.7 |
| Average firm transportation - capacity reservation (MMcf/d) | 653.7 | 577.9 | 640.7 |
| Average interruptible transportation - throughput (MMcf/d) | 410.3 | 468.9 | 389.2 |

Revenue. Segment revenue for the year ended December 31, 2015, was $43.7 million compared to $88.2 million for the year ended December 31, 2014. This decrease of $44.5 million in revenue was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements during the first quarter of 2015, which substantially reduced the sales of natural gas throughput volumes and also the need for us to purchase such volumes; and lower average throughput volumes of 70.3 MMcf/d primarily attributable to our Midla and High Point Systems.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2015, were $8.3 million compared to $45.3 million for the year ended December 31, 2014. This decrease of $37.0 million was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements, and therefore substantially reducing our need to purchase natural gas.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015, was $35.3 million compared to $42.8 million for the year ended December 31, 2014. This decrease of $7.5 million was primarily due to changes in pipeline imbalances and lower interruptible transportation margins period over period due to lower average throughput volumes of 70.3 MMcf/d, or 9.0%.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015, were $13.7 million compared to $15.6 million for the year ended December 31, 2014. This decrease of $1.9 million was primarily related to the timing of activities associated with our integrity management program and lower insurance premiums, year over year.

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

Revenue. Segment revenue for the year ended December 31, 2014, was $88.2 million compared to $79.0 million for the year ended December 31, 2013. This increase of $9.2 million was primarily due to higher realized natural gas prices on our fixed-margin arrangements of $0.84/Mcf, or 22.1%, and an increase in the average throughput volumes on our transmission systems to 778.9 MMcf/d for the year ended December 31, 2014 compared to 644.7 MMcf/d for the year ended December 31, 2013, representing a 20.8% increase period over period. This increase in the average throughput volumes was primarily due to higher throughput volumes at our High Point System of 147.9 MMcf/d resulting from twelve months of activity in 2014 compared to less than nine months in 2013, partially offset by lower natural gas throughput volumes of 19.5 MMCf/d primarily related to our Midla and Trigas systems. The higher realized natural gas prices on our fixed-margin arrangements were partially offset by lower sales volumes of 1.9 MMcf, or 19.0%

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2014, were $45.3 million compared to $46.5 million for the year ended December 31, 2013. This decrease of $1.2 million was primarily due to higher realized natural gas prices, which resulted in higher natural gas purchase costs associated with our fixed-margin arrangements; and an extinguishment of a reserve associated with lower lost and unaccounted for gas on our High Point System.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014, was $42.8 million compared to $32.4 million for the year ended December 31, 2013. This increase of $10.4 million was primarily due to increased gross margin associated with our High Point System of $12.0 million resulting from twelve months of activity in 2014 compared to less than nine months in 2013; and an extinguishment of a reserve associated with lower lost and unaccounted for gas on our High Point System.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $15.6 million compared to $13.3 million for the year ended December 31, 2013. This increase of $2.3 million was primarily due to increased costs associated with our High Point System having twelve months of activity in 2014 compared to less than nine months in 2013.

Terminals Segment

The table below contains key segment performance indicators related to our Terminals segment (in thousands except operating data).

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Segment Financial and Operating Data: | | | |
| Terminals segment | | | |
| Financial data: | | | |
| Total revenue | $17,755 | $15,504 | $9,831 |
| Direct operating expenses | 6,640 | 6,342 | 4,403 |
| Other financial data: | | | |
| Segment gross margin | $11,115 | $9,162 | $5,428 |
| Operating data: | | | |
| Contracted Capacity (Bbls) | 1,487,542 | 1,247,058 | 1,114,792 |
| Design Capacity (Bbls) | 1,688,950 | 1,363,817 | 1,165,600 |
| Storage Utilization (a) | 88.1 % | 91.4 % | 95.6 % |

(a) Excludes storage utilization associated with our discontinued operations.

Revenue. Segment total revenue for the year ended December 31, 2015, was $17.8 million compared to $15.5 million for the year ended December 31, 2014. The increase of $2.3 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at the Harvey and Westwego terminals and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015 were $6.6 million compared to $6.3 million for the year ended December 31, 2014. The increase of $0.3 million is primarily attributable to additional direct labor associated with providing ancillary services.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015, was $11.1 million compared to $9.2 million for the year ended December 31, 2014. The increase of $1.9 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

The acquisition of Blackwater 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, which is the date common control began.

Revenue. Segment total revenue for the year ended December 31, 2014, was $15.5 million compared to $9.8 million for the year ended December 31, 2013. The increase of $5.7 million was primarily attributable to presenting twelve months of activity in 2014 compared to less than nine months in 2013, and an increase in storage capacity, acquiring new customers and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $6.3 million compared to $4.4 million for the year ended December 31, 2013. The increase of $1.9 million is primarily attributable to additional direct labor hours associated with providing ancillary services, and by presenting twelve months of activity in 2014 compared to less than nine months in 2013.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014, was $9.2 million compared to $5.4 million for the year ended December 31, 2013 as a result of the increase in storage capacity, acquiring new customers and contractual storage rate escalations.

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.

Our principal sources of liquidity include borrowings under our Credit Agreement, issuance of equity in the capital markets or through private transactions, and financial support from ArcLight, who controls our General Partner. In addition, we may seek to

72

raise capital through the issuance of equity and unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that cash generated from our operating activities and the sources of liquidity described above will be sufficient to meet our short-term working capital requirements, medium-term maintenance capital expenditure requirements, and quarterly cash distributions for at least the next four quarters. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, additional forms of debt or equity financing. In addition, we would reduce capital expenditures, direct operating expenses and selling, general and administrative expenses, as necessary, and our Partnership Agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations.

Our liquidity for the year ended December 31, 2015 was impacted by the following:

- issuances of 2,571,430 Series A-2 Units for $45.0 million in net proceeds, which were used to pay down outstanding borrowings under the Credit Agreement;
- issuance of 7,500,000 Limited Partner common units for $81.0 million in net proceeds which were used to partially fund our investment in Delta House; and
- completion of the First Amendment to the Credit Agreement dated as of September 5, 2014, which increased our borrowing capacity from $500.0 million to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million subject to lender approval.

Changes in natural gas, crude oil, 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 (loss), along with the resulting changes in working capital. During 2015, we 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 is determined on a counterparty by counterparty basis, and is impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative natural gas and crude oil 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. As of December 31, 2015, we had no collateral risk.

Our Credit Agreement

On September 18, 2015, the Partnership entered into the First Amendment to the Partnership's Credit Agreement, which provides for maximum borrowings equal to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million subject to lender approval. The Credit Agreement contains certain financial covenants, including i) a consolidated leverage ratio that requires our indebtedness not to exceed 4.75 times adjusted consolidated EBITDA (as defined in the Credit Agreement) for the prior twelve month period (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted consolidated EBITDA), and ii) a minimum interest coverage ratio that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by at least 2.50 times. The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $750.0 million. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate plus a margin ranging from

2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

Our obligations under the Credit Agreement are secured by a lien on substantially all of our assets. Advances made under the Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the Credit Agreement include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, which is September 5, 2019.

The Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

As of December 31, 2015, our consolidated total leverage ratio was 4.56 and our interest coverage ratio was 8.56, which were in compliance with the financial covenants required in the Credit Agreement. The maximum permitted consolidated total leverage ratio was 5.25 for the twelve month period ended December 31, 2015, as result of our indirect investment in Delta House in September 2015. The maximum permitted consolidated total leverage ratio will revert to 4.75 for the period ended June 30, 2016. As of December 31, 2015, we had approximately $525.1 million of outstanding borrowings under the $750.0 million Credit Agreement.

At December 31, 2015 and 2014, letters of credit outstanding under the Credit Agreement were $1.8 million and $1.6 million, respectively.

As of December 31, 2015, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions, or drop down transactions, as well as the associated financing for such initiatives. If required, ArcLight Capital Partners, which controls the General Partner of the Partnership, has agreed to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through December 31, 2016.

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 deficit was $10.1 million at December 31, 2015.

Cash Flows

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

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Net cash provided by (used in): | | | |
| Operating activities | $40,937 | $21,478 | $17,223 |
| Investing activities | (171,108) | (471,870) | (28,214) |
| Financing activities | 129,672 | 450,490 | 10,816 |

Year Ended December 31, 2015, Compared to Year Ended December 31, 2014

Operating Activities. Net cash provided by operating activities was $40.9 million for year ended December 31, 2015, compared to $21.5 million for the year ended December 31, 2014. Net cash provided by operating activities for the year ended December 31, 2015 increased by $19.4 million period over period primarily due to increased gross margin of $20.5 million, an increase in the change in operating assets and liabilities of $16.1 million, and an increase in earnings from unconsolidated affiliates of $7.9 million. These increases in operating cash flows were partially offset by increases in direct operating expenses and selling, general and administrative expenses of $13.8 million and $4.1 million, respectively, and an increase in interest expense of $7.2 million due to a higher outstanding borrowings as a result of the Costar acquisition and Delta House Investment; as well as, funding our capital growth projects during the current year.

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

Investing Activities. Net cash used in investing activities was $171.1 million for the year ended December 31, 2015, compared to $471.9 million for the year ended December 31, 2014. Cash used in investing activities for the year ended December 31, 2015 decreased by $300.8 million period over period primarily due to no cost of acquisitions for 2015 and cash received from acquisitions of $7.4 million in 2015 as compared to cost of acquisitions of $362.3 million in 2014, primarily related to reimbursement for certain capital expenditures that we have incurred, or will incur, related to the Costar acquisition, return of restricted cash of $6.5 million, and higher cash disbursements received from unconsolidated affiliates in excess of cumulative earnings of $10.7 million. These increases were offset by higher capital expenditures of $33.6 million primarily related to the Lavaca and Bakken Systems, and higher cash disbursements of $59.6 million related to equity method investments primarily related to the Delta House Investment.

Financing Activities. Net cash provided by financing activities was $129.7 million for the year ended December 31, 2015, compared to $450.5 million for the year ended December 31, 2014. Cash provided by financing activities for the year ended December 31, 2015, decreased by $320.8 million period over period primarily due to lower proceeds from the issuance of common units to the public of $121.8 million, cash distributions in excess of carrying value received related to the Delta House Investment of $96.3 million, lower net borrowings period over period of $90.1 million, the absence of proceeds received from the issuance of Series B Units in 2014, and an increase in unit holder distributions of $25.4 million. These decreases in cash flows provided by financing activities were partially offset by the issuance of Series A-2 units for gross proceeds of $45.0 million.

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

Operating Activities. Net cash provided by operating activities was $21.5 million for year ended December 31, 2014, compared to $17.2 million for the year ended December 31, 2013. Net cash provided by operating activities for the year ended December 31, 2014, increased primarily due to increased gross margin of $28.0 million and a decrease in interest expense of $1.7 million. These increases were partially offset by $13.5 million of additional direct operating expenses associated with incremental operating expense of the gathering and processing systems of Costar, an increase in compression rentals, costs associated with integrity management programs and additional aerial pipeline inspections, an increase of $4.0 million associated with higher salaries and wages associated with new personnel additions and legal costs incurred to manage and integrate our acquisitions and support our continued growth, and settlement of asset retirement obligations of $1.0 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 $471.9 million for the year ended December 31, 2014, compared to $28.2 million for the year ended December 31, 2013. Cash used in investing activities for the year ended December 31, 2014 increased by $443.7 million period over period primarily due to incremental payments of $362.3 million used to fund the acquisition of gathering and processing assets, $69.8 million of additional capital expenditures primarily associated with expansion capital programs related to the Lavaca System and new terminal storage facilities at Westwego and Harvey, Louisiana, and $12.0 million associated with acquisition of a 66.7%

undivided interest in MPOG. These increases were partially offset by $5.8 million of proceeds related to the divestiture of non-strategic midstream assets.

Financing Activities. Net cash provided by financing activities was $450.5 million for the year ended December 31, 2014, compared to net cash provided by financing activities of $10.8 million for the year ended December 31, 2013. Cash provided by financing activities for the year ended December 31, 2014, increased by $439.7 million period over period primarily due to incremental proceeds from the issuance of common units to the public of $204.3 million and the issuance of Series B Units of $30.0 million, and an increase of $239.8 million in net borrowings from our credit facility in order to finance, in part, the acquisition of Costar.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2015, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. There are no other transactions, arrangements, or other relationships associated with our investments in unconsolidated affiliates or related parties that are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources. At December 31, 2015, our off-balance sheet arrangements did not change materially from those listed in "Item 7. Management's Discussion and Analysis — Contractual Obligations".

Capital Requirements

The energy business is 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) made to maintain our operating income or operating capacity; or

- expansion capital expenditures, incurred for acquisitions of capital assets 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, 2015, capital expenditures totaled $130.5 million including expansion capital expenditures of $120.1 million, maintenance capital expenditures of $4.5 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 $6.0 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 $45.0 million and $55.0 million for the year ending December 31, 2016. Forecasted growth capital expenditures include construction of midstream infrastructure for the Permian Off-spec treating facility, expansion of the Harvey terminal, continued build-out of Lavaca system, completion of the Longview Rail and Yellow Rose facilities, and other organic growth projects.

We intend to make cash distributions to our unitholders and our General Partner and expect that we will distribute most of the cash generated by our operations.

As a result, we expect to fund acquisitions and future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, and additional debt and equity issuances. If these sources are not sufficient, we may pursue the divestiture of non-core assets or reduce 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 93 high consequence areas that require on-going testing pursuant to DOT regulations. Over the course of the seven-year cycle, we expect to incur up to $7.2 million in integrity management testing expenses.

Distributions

On January 25, 2016, we announced a distribution of $0.4725 per unit for the fourth quarter ended December 31, 2015, or $1.89 per unit on an annualized basis. The cash distribution was paid on February 12, 2016, to unitholders of record as of the close of business on February 3, 2016.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2015 (in thousands):

| | Total | Long-term debt | Operating leases and service contracts | Asset retirement obligation |
|---|---|---|---|---|
| Less Than 1 Year | $12,881 | $2,338 | $3,721 | $6,822 |
| 1 - 3 Years | 3,459 | — | 3,459 | — |
| 3 - 5 Years | 527,451 | 525,100 | 2,351 | — |
| More Than 5 Years | 30,086 | — | 1,537 | 28,549 |
| Total | $573,877 | $527,438 | $11,068 | $35,371 |

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, 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. 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. An asset or asset group is considered impaired when the estimated undiscounted cash flows are less than the carrying amount. In that event, an impairment loss is recognized to the extent that the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations. We recorded impairments of long-lived assets of $0.0 million, $99.9 million and $18.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. A hypothetical increase or decrease in fair value by 1.0% would have changed our impairment by less than $1.0 million for the year ended December 31, 2014.

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. We recorded an impairment of goodwill of $118.6 million for the year ended December 31, 2015.

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, 2015, we did not record any liability for remediation expenditures. If governmental regulations change, we could be required to incur remediation costs that may have a material impact on our profitability.

Asset Retirement Obligations. As of December 31, 2015, we recorded liabilities of $35.4 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, crude oil, 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.

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. 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, 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.

Recent Accounting Pronouncements

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, please refer to Note 1 "Organization, Basis of Presentation and Summary of Significant Accounting Policies"
in Part II, Item 8 of this Annual Report, which is incorporated herein by reference.

Accounting Standards Update ("ASU") No. 2015-02, Consolidation - Amendments to the Consolidation Analysis

In February 2015, the FASB issued a final standard that amends the current consolidation guidance. The amendments affect both the variable interest entity ("VIE") and voting interest entity ("VOE") consolidation models. The standard is effective for public reporting entities in the fiscal periods beginning after December 15, 2015, early adoption is permitted. We have evaluated the impact of this ASU to the Partnership's consolidated financial statements and footnotes thereto and believe the changes may be significant in the future. Changes to variable and voting interest models associated with certain legal entities under the new consolidation model could change previous consolidation conclusions.

ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606)

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting standards for revenue recognition. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods therein. Early adoption is not permitted. We have begun assessing the impact of this ASU to the Partnership's consolidated financial statements and footnotes thereto and believe the level of effort to ensure all transaction types are appropriately analyzed to be significant. Our assessment to-date considers alternatives of the transition methods, a portfolio approach to significant contract-types and required changes to disclosure to the consolidated financial statements. In light of performance obligations, effects of variable consideration and enhanced disclosure, we expect the adoption of this ASU to have a significant impact to the Partnership's consolidated financial statements and footnotes thereto.

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, crude oil, 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, crude oil and NGL prices are impacted by changes in the supply and demand for these energy commodities, as well as market uncertainty. For a discussion of the volatility of natural gas, crude oil, and NGL prices, please refer to "Item 1A. Risk Factors." Adverse effects on our cash flow from reductions in natural gas, crude oil and NGL prices could adversely affect our operating cash flows and 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. Historically, the commodity derivatives are in the form of swaps and collars.

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, 2015, 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.

During 2015, we entered into additional commodity contracts with existing counterparties to hedge our 2015 exposure to commodity prices. Due to declining commodity prices, we had not entered into commodity contracts to hedge production in 2016 and beyond as of December 31, 2015.

Interest Rate Risk

During the year ended December 31, 2015, we had exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. To manage the impact of the interest rate risk associated with our Credit Agreement, we enter into interest rate swaps from time to time, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows. The notional amount of our interest rate swap that expired on August 1, 2015 was $100.0 million.

On March 2, 2016, we entered into interest rate swaps with a notional amount of $200.0 million that will expire in September 2019.

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. For example, on December 16, 2015, the Federal Open Market Committee raised the target range for the federal funds rate by 0.25%. Future 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 $4.4 million for the year ended December 31, 2015.

## 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. The Certifying Officers evaluated the effectiveness of the Partnership’s disclosure controls and procedures as of December 31, 2015. Based on this assessment, the Certifying Officers concluded that the Partnership’s disclosure controls and procedures were effective as of December 31, 2015.

### Inherent limitations of internal controls

Our management, including our Certifying Officers, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) will prevent or detect 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 prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. 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 controls. 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 with a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Therefore, management monitors the Partnership's disclosure controls and procedures and make modifications, as necessary, with the intent that the disclosure controls and procedures will be adequately designed and operating effectively to prevent or detect material misstatements to its consolidated financial statements and to deter fraud.

Remediation of spreadsheet deficiencies

We did not design and maintain effective internal controls over financial reporting regarding the completeness and accuracy of spreadsheets. Specifically, our guidelines were not precise enough in describing the level of review to be performed regarding the inputs, assumptions, and formulas used in spreadsheets. This control deficiency resulted in audit adjustments to goodwill, intangible assets, and amortization expense during the year ended December 31, 2014 and immaterial out-of-period adjustments to our consolidated financial statements for each of the interim periods in the year-ended December 31, 2014. Additionally, this control deficiency could have resulted in a material misstatement of our annual or interim consolidated financial statements that may not have been prevented or detected. Accordingly, management determined that this control deficiency constituted a material weakness.

With respect to the identified material weakness, we have assessed, developed and implemented specific guidance and procedures describing the expected level of reviews to be performed on our key spreadsheets used in the preparation and analysis of accounting and financial information. This includes the validation of inputs, assumptions and formulas.  We believe this process is appropriately designed to strengthen controls surrounding the use of our key spreadsheets. Management tested the newly implemented and modified controls and found them to be effective and concluded that as of December 31, 2015, the material weakness has been remediated.

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 Rules 13a-15(f) and 15d-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.

The Certifying Officers assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2015. This assessment was based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on their assessment, the Certifying Officers concluded that as of December 31, 2015 the Partnership’s internal control over financial reporting was effective.

PricewaterhouseCoopers LLP, the independent registered public accounting firm, that audited the consolidated financial statements included in this Annual Report on Form 10-K, has audited the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2015, as stated in their report which is included on page F-1 of this Annual Report.

Changes in internal control over financial reporting

Management, including our Certifying Officers, evaluated the changes in our internal control over financial reporting for the quarter ended December 31, 2015. As outlined above, management remediated the material weakness that existed during 2015. As such, certain changes related to spreadsheets that operated on an annual basis occurred in the fourth quarter related to the remediation of the material weakness described above and were considered changes to the Partnership’s internal control over financial reporting during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The certifications of our Certifying Officers 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 Certifying Officers 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

Amendment to Employment Agreement

On March 7, 2016, the General Partner entered into the Second Amendment to Employment Agreement (the "Second Amendment") with Michael D. Suder, Chief Executive Officer of Blackwater Midstream. The Second Amendment revises the definitions of the terms "Blackwater Harvey" and "Blackwater Direct SG&A" in the underlying Employment Agreement in order to maintain previously existing economic structure of the Employment Agreement in light of certain internal contract assignments between entities wholly-owned by the Partnership. This description of the Second Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Second Amendment, which is filed as an exhibit to this Form 10-K and incorporated by reference herein.

82

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. HPIP and AIM Midstream Holdings own all of the membership interests in our General Partner. Our General Partner has a board of directors (the "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 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 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 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 and not a breach by our General Partner of any duties it may owe us or our unitholders. In addition, the Board has an Audit Committee ("Audit Committee"), that complies with the NYSE requirements, a compensation committee ("Compensation Committee"), and a hedge committee that oversees 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.

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 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 Board are Donald R. Kendall Jr., Rose M. Robeson and Gerald A. Tywoniuk. Each of our independent directors serves as a member 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 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 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, 2015:

| Name | Age | Position with American Midstream GP, LLC |
|---|---|---|
| Lynn L. Bourdon III (a) | 53 | Chairman of the Board, President and Chief Executive Officer |
| Tom L. Brock | 43 | Vice President, Chief Accounting Officer and Corporate Controller |
| Daniel C. Campbell | 45 | Senior Vice President and Chief Financial Officer |
| Louis J. Dorey | 60 | Senior Vice President of Business Development |
| William B. Mathews | 63 | Secretary, General Counsel and Senior Vice President of Legal Affairs |
| Matthew W. Rowland | 53 | Senior Vice President and Chief Operating Officer |
| Michael D. Suder | 61 | President and Chief Executive Officer of Blackwater Midstream Corporation |
| Stephen W. Bergstrom (b) | 58 | Director |
| John F. Erhard | 41 | Director |
| Donald R. Kendall Jr. | 63 | Director |
| Daniel R. Revers | 54 | Director |
| Rose M. Robeson | 55 | Director |
| Joseph W. Sutton | 67 | Director |
| Lucius H. Taylor | 42 | Director |
| Gerald A. Tywoniuk | 54 | Director |

(a) Mr. Bourdon was appointed to serve as Chairman of the Board, President and Chief Executive Officer effective December 10, 2015.

(b) Mr. Bergstrom was compensated in 2015 through an agreement with HPIP, the majority owner of our General Partner. Accordingly, Mr. Bergstrom allocated time to HPIP and our General Partner on matters not related to the Partnership during 2015, none of which was considered compensation for services rendered in conjunction with his former role as Executive Chairman, President and Chief Executive Officer of the Partnership. Mr. Bergstrom retired in December 2015 from these positions but remains on the Board of Directors.

Executive officers

Lynn L. Bourdon III was appointed Chairman, President and Chief Executive Officer in December 2015. Most recently, Mr. Bourdon served as President and Chief Executive Officer of Enable Midstream Partners, LP. Prior to Enable Midstream, he served as Group Senior Vice President of NGL & Natural Gas Marketing, Petrochemical, Refined Products & Marine Services at Enterprise Products Partners, LP. Mr. Bourdon joined Enterprise as Senior Vice President of NGL Supply & Marketing in 2003 and served in various senior management positions during his tenure. Prior to his employment at Enterprise Products, Mr. Bourdon served as Senior Vice President and Chief Commercial Officer for Orion Refining Corporation. He also held leadership positions at En*Vantage, PG&E Gas Transmission and Valero, and earlier served in various capacities at the Dow Chemical Company. Lynn received a Bachelor of Science degree in mechanical engineering from Texas Tech University and an MBA from the University of Houston.

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 the General Partner, 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.

Louis J. Dorey has served as Senior Vice President of Business Development since joining American Midstream LP, in January of 2014. Previously he served in various capacities at Continuum Energy Services from 2005 to 2014, including strategic planning, mergers and acquisitions, corporate business development, capital markets activities and as interim CFO. During his tenure, Continuum acquired or developed 500 miles of gathering systems, 75 MMcf/d of processing capacity, a rail terminal, a crude oil trucking company and raised two tranches of private equity. Prior to joining Continuum, Mr. Dorey was employed by Dynegy Inc. from 1997 to 2002 where he held positions including Executive Vice President of Strategy and Planning, President of Marketing and Origination, and Interim CFO. He participated in over $2 billion of acquisitions and development transactions, managed five regional wholesale marketing offices and retail marketing group, and worked on the integration of two major mergers. From 1991 to 1997, Mr. Dorey was employed by Destec Energy Inc. where he served as the Vice President of Mergers and Acquisitions, leading the development or acquisition of over $2 billion of power plant transactions and the sale of Destec Energy Inc. to Dynegy Inc. He earned a Bachelor of Business Administration from the University of Oklahoma and a Juris Doctorate from the University of Texas.

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 the General Partner, 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.

Michael D. Suder has served as President and CEO of Blackwater Midstream since 2008. Mr. Suder is the former President and Chief Operating Officer of Delta Terminal Services in Harvey, Louisiana, and member of the investment group with Citicorp Venture Capital that purchased the terminal in January 1995. He was responsible for growing the facility from 1.5 million barrels to more than 3 million barrels in storage capacity, including the addition of more than 100 new tanks and new drumming warehouses. After Delta Terminal Services was sold to Kinder Morgan Energy Partners in December 2000, Mr. Suder became the General Manager of Kinder Morgan’s Lower Mississippi River region. He was responsible for all aspects of the liquid terminals in the region. He held that position from 2001 until 2005. From September 2005 to June 2007, Mr. Suder was the Director of New Business Development for LBC Tank Terminals. He oversaw the growth at their Baton Rouge facility, where capacity increased by more than 1 million barrels. LBC Tank Terminals was sold to Challenger Financial Services in June of 2007. In 2008, Mr. Suder, President and CEO of Blackwater Midstream, and his management team commenced operations at Blackwater Midstream’s newly-acquired Westwego, Louisiana, facility. American Midstream acquired Blackwater Midstream in December 2013. Under Mr. Suder’s guidance, Blackwater has expanded to four terminal facilities throughout three strategic regions, currently servicing the Gulf Coast, Southeast, and Northeast United States storage markets. Mr. Suder holds a B.A. from George Washington University in Washington, D.C.

Directors

Stephen W. Bergstrom was elected as a member of the Board in April 2013 and was elected President and Chief Executive Officer in May 2013 and served as President and Chief Executive Officer until retiring from those positions in December 2015. He remains a member of the Board. 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.

John F. Erhard was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Erhard, a Partner at ArcLight, joined the firm in 2001 and has 15 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.

Donald R. Kendall, Jr. was elected a member of the Board 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. Previously, 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. He also currently serves as a director and audit committee chairperson of SolarCity and Stream Energy and as a director of 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. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

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. Mr. Revers is Managing Partner of and a co-founder of ArcLight and has 25 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' 25 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Rose M. Robeson was elected as a member of the Board in June 2014. Ms. Robeson serves as an independent director and as a member of the Audit Committee. Ms. Robeson also has served as a director of SM Energy since July 2014 and of Tesco Corporation since October 2015. Ms. Robeson most recently served as Senior Vice President and Chief Financial Officer of DCP Midstream GP, LLC, the General Partner of DCP Midstream Partners LP, from 2012 to 2014. Ms. Robeson also served as Group Vice President and Chief Financial Officer of DCP Midstream LLC from 2002 to 2012. Prior to her appointment as CFO of DCP Midstream LLC, Ms. Robeson was the Vice President and Treasurer at DCP, and previously served as Vice President and Treasurer at Kinder Morgan as well as in a number of finance and accounting positions at Total Petroleum (North America) Ltd. Ms. Robeson began her career primarily with Ernst & Young as a certified public accountant. We believe Ms. Robeson's extensive accounting, financial and executive management experience, and her prior experience with publicly traded partnerships, provide her with the necessary skills to be a member of the Board and a member of the Audit Committee. With respect to the Audit Committee, she also qualifies as an "audit committee financial expert."

Joseph W. Sutton was elected as a member of the Board 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.

Lucius H. Taylor was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Taylor joined ArcLight in 2007. He has 16 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 16 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Gerald A. Tywoniuk was elected as a member of the Board 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 Westmoreland Resource Partners, LP (NYSE:WMLP) and serves as a director and audit committee member on the board of the General Partner of Landmark Infrastructure Partners LP (NASDAQ:LMRK). 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 33 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 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 on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2015, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, except as set forth below:

March 4, 2016
- Late filing of a Form 4 for Timothy Balaski (1 day late);
- Late filing of a Form 4 for Tom Brock (1 day late);
- Late filing of a Form 4 for Ryan Rupe (1 day late);
- Late filing of a Form 4 for Robert Bourne (1 day late);

- Late filing of a Form 4 for Michael Suder (1 day late);
- Late filing of two Forms 4 for Daniel Campbell (1 day late);
- Late filing of a Form 4 for Kevin Sullivan (1 day late);
- Late filing of a Form 4 for Louis Dorey (1 day late);
- Late filing of a Form 4 for Matthew Rowland (1 day late); and
- Late filing of two Forms 4 for William Mathews (1 day late).

## Item 11. Executive Compensation

Our General Partner, under the direction of 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, 2015:

| Name | Position with American Midstream GP, LLC |
|---|---|
| Lynn L. Bourdon III (a) | Chairman of the Board, President, and Chief Executive Officer |
| Stephen W. Bergstrom (b) | Former Executive Chairman of the Board, 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 |
| Louis J. Dorey | Senior Vice President of Business Development |
| Michael D. Suder | President and Chief Executive Officer of Blackwater Midstream Corporation. |

(a) Mr. Bourdon was appointed to serve as Chairman of the Board, President and Chief Executive Officer effective December 10, 2015.

(b) Mr. Bergstrom was compensated in 2015 through an agreement with HPIP, the majority owner of our General Partner. Accordingly, Mr. Bergstrom allocated time to HPIP and our General Partner on matters not related to the Partnership during 2015, none of which was considered compensation for services rendered in conjunction with his former role as Executive Chairman, President and Chief Executive Officer of the Partnership. Mr. Bergstrom retired in December 2015 from these positions but remains on the Board of Directors.

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 unitholders, 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, 2015.

### 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 of compensation and allocation among components of their annual compensation will be reviewed on at least an annual basis by the Compensation Committee.

During 2015, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2016 and in future years. Topics discussed and to be discussed at these meetings included and will include, among other things, i) assessing the performance of the Chief Executive Officer, 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 Chief Executive Officer only with respect to executive officers and key managers other than our Chief Executive Officer, 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 and recommend awards to the Board. Our Chief Executive Officer 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 performance 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 distributable cash flow. 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 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: Blueknight Energy Partners LP, Crestwood Midstream Partners LP, Genesis Energy LP, JP Energy Partners LP, Martin Midstream Partners LP, and Rose Rock Midstream, LP.

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. Distribution Equivalent Rights, or DERs, and options have been granted on a limited basis. Future awards, such as options and DERs may be granted at the discretion of the Compensation Committee and subject to the approval of 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. |
| Retirement Plan | Qualified retirement plan benefits are available for our executive officers and all other regular full-time employees. At our formation, we adopted and are maintaining a tax-deferred or after-tax 401(k) plan in which all eligible employees can elect to defer compensation for retirement up to IRS imposed limits. The 401(k) plan permits us to make annual discretionary matching contributions to the plan. For 2015, we matched employee contributions to 401(k) plan | Provide our executive officers and other employees with the opportunity to save for their future retirement. |

| | | |
|---|---|---|
| | 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, 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 Chief Executive Officer 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 Chief Executive Officer.

The Compensation Committee approved the following base salaries for 2015 for the named executive officers as provided in the table below.

| Name | Base Salary at the end of 2015 |
|---|---|
| Lynn L. Bourdon III (a) | $500,000 |
| Stephen W. Bergstrom (b) | nm |
| Daniel C. Campbell | 285,000 |
| Matthew W. Rowland | 285,000 |
| Louis J. Dorey | 275,520 |
| Michael D. Suder | 300,000 |

(a) Mr. Bourdon was appointed to serve as Chairman of the Board, President and Chief Executive Officer effective December 10, 2015.

(b) Mr. Bergstrom was compensated in 2015 through an agreement with HPIP, the majority owner of our General Partner. Accordingly, Mr. Bergstrom allocated time to HPIP and our General Partner on matters not related to the Partnership during 2015, none of which was considered compensation for services rendered in conjunction with his former role as Executive Chairman, President and Chief Executive Officer of the Partnership. Mr. Bergstrom retired in December 2015 from these positions but remains on the Board of Directors.

nm Not meaningful

Annual Incentive Bonuses

As one way of accomplishing our 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 Chief Executive Officer 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 Chief Executive Officer.

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 Chief Executive Officer 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 Chief Executive Officer.

While target bonuses for our executive officers who have entered into employment agreements have been initially set at dollar amounts that are between 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 2015 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 2015, 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 expenditure programs in 2015;
- a subjective individual performance evaluation for executive officers and other factors deemed 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 were 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 determined to award the base salary and incentive bonus amounts, which may be paid in cash or Common Units, set forth in the table below to our named executive officers for performance in 2015.

| Name | 2015 Base Salary | 2015 Target Bonus | 2015 Bonus Earned |
|---|---|---|---|
| Lynn L. Bourdon III (a) | $500,000 | $— | $— |
| Stephen W. Bergstrom (b) | nm | — | — |
| Daniel C. Campbell | 285,000 | 213,750 | 130,000 |
| Matthew W. Rowland | 285,000 | 213,750 | 130,000 |
| Louis J. Dorey | 275,520 | 206,640 | 124,000 |
| Michael D. Suder | 300,000 | 225,000 | 200,000 |

(a) Mr. Bourdon was appointed to serve as Chairman of the Board, President and Chief Executive Officer effective December 10, 2015.

(b) Mr. Bergstrom was compensated in 2015 through an agreement with HPIP, the majority owner of our General Partner. Accordingly, Mr. Bergstrom allocated time to HPIP and our General Partner on matters not related to the Partnership during 2015, none of which was considered compensation for services rendered in conjunction with his former role as Executive Chairman, President and Chief Executive Officer of the Partnership. Mr. Bergstrom retired in December 2015 from these positions but remains on the Board of Directors.

Beginning in 2015, 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 weight to any factor):

- financial performance for the prior fiscal year, including Adjusted EBITDA and distributable cash flow;
- 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 November 2009 in connection with our formation and was 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. In December 2015, we granted phantom units with associated DERs to provide long-term incentives to a named executive officer. DERs enable the recipients of phantom unit awards to receive cash distributions on our phantom units to the same extent generally as unitholders receive cash distributions on our Common Units.
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. 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. 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. The LTIP is administered by the Compensation Committee of the Board. The Compensation Committee, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash.
Generally, grants issued under the LTIP vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment. Ownership in the awards is subject to forfeiture until the vesting date.

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) plan. The 401(k) plan allows our 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 2015, 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 2015 and 2014, 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 2015, in light of current legislative policies as well as economic and market conditions.
Employment, Change in Control 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 entered into employment agreements with each of Messrs. Campbell, Suder, Bourdon, and Rowland 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, 2015

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, 2015.

| | Year | Salary | Bonus | Unit Awards (a) | All Other Compensation (d) | Total Compensation |
|---|---|---|---|---|---|---|
| Lynn L. Bourdon III (b) Chairman of the Board, President and Chief Executive Officer | 2015 | $32,692 | $— | $1,501,952 | $— | $1,534,644 |
| Stephen W. Bergstrom (c) | 2015 | nm | — | — | — | — |
| Former Executive Chairman, President and Chief Executive Officer | 2014 | nm | — | — | — | — |
| | 2013 | nm | — | — | — | — |
| Daniel C. Campbell Senior Vice President | 2015 | 295,962 | 28,000 | 591,549 | — | 915,511 |
| and Chief Financial Officer | 2014 | 285,000 | 250,000 | 352,492 | — | 887,492 |
| | 2013 | 235,000 | 132,000 | 213,230 | — | 580,230 |
| Matthew W. Rowland Senior Vice President | 2015 | 295,962 | 28,000 | 412,041 | — | 736,003 |
| and Chief Operating Officer | 2014 | 285,000 | 250,000 | 352,492 | — | 887,492 |
| | 2013 | 122,577 | — | 527,000 | — | 649,577 |
| Louis J. Dorey Senior Vice President of Business Development | 2015 | 285,577 | 28,000 | 427,031 | 99,095 | 839,703 |
| Michael D. Suder President and Chief | 2015 | 311,538 | 28,000 | 437,489 | — | 777,027 |
| Executive Officer of Blackwater Midstream | 2014 | 304,423 | 40,625 | — | — | 345,048 |
| | 2013 | 408,750 | | | | |