ATLAS PIPELINE PARTNERS LP
Form 10-K
February 20, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

OR

¨ **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: 1-14998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE **(State or other jurisdiction of incorporation or organization)**	**23-3011077** **(I.R.S. Employer Identification No.)**
Park Place Corporate Center One **1000 Commerce Drive, 4th Floor** **Pittsburgh, Pennsylvania** **(Address of principal executive office)**	**15275-1011** **(Zip code)**

Registrant s telephone number, including area code: (877) 950-7473

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

(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

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 definitions of large accelerated filer, accelerated filer and small reporting company in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

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

The aggregate market value of the equity securities held by non-affiliates of the registrant, based upon the closing price of $38.19 per common limited partner unit on June 30, 2013, was approximately $2,714.2 million.

The number of common units of the registrant outstanding on February 17, 2014 was 80,595,148.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as anticipate, believe, continue, could, estimate, expect, intend, may, might, plan, potential, predict, should, or will, or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

- *the demand for natural gas, NGLs and condensate;*
- *the price volatility of natural gas, NGLs and condensate;*
- *our ability to connect new wells to our gathering systems;*
- *our ability to integrate operations and personnel from acquired businesses;*
- *adverse effects of governmental and environmental regulation;*
- *limitations on our access to capital or on the market for our common units; and*
- *the strength and financial resources of our competitors.*

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under Item 1A, Risk Factors in this report. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

Glossary of Terms

Definitions of terms and acronyms generally used in the energy industry and in this report are as follows:

BPD	Barrels per day. Barrel measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BTU	British thermal unit, a basic measure of heat energy
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is a non-GAAP measure.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fractionation	The process used to separate an NGL stream into its individual components.
GAAP	Generally Accepted Accounting Principles
G.P.	General Partner or General Partnership
GPM	Gallons per minute
IFRS	International Financial Reporting Standards
Keep-Whole	A contract with a natural gas producer whereby the plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head.
L.P.	Limited Partner or Limited Partnership
MCF	Thousand cubic feet
MCFD	Thousand cubic feet per day
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
NGL(s)	Natural Gas Liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline
Percentage of Proceeds, (POP)	A contract with a natural gas producer whereby the plant operator retains a negotiated percentage of the sale proceeds.
Residue gas	The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.
SEC	Securities and Exchange Commission

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PART I

ITEM 1. BUSINESS
Corporate Structure

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering, processing and treating services primarily in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in south Texas; a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States and a provider of NGL transportation services in the southwestern region of the United States.

Our general partner, Atlas Pipeline Partners GP, LLC (Atlas Pipeline GP or the General Partner), manages our operations and activities through its ownership of our general partner interest. Atlas Pipeline GP is a wholly-owned subsidiary of Atlas Energy, L.P. (ATLS), a publicly traded Delaware limited partnership (NYSE: ATLS), which owned 6.0% of the limited partner interests in us at December 31, 2013, as well as a 2.0% general partner interest.

The following chart displays the corporate organizational structure as of December 31, 2013:

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Recent Developments

Acquisitions

On May 7, 2013, we completed the acquisition of 100% of the equity interests of TEAK Midstream, L.L.C. (TEAK) for $974.7 million in cash, including final purchase price adjustments, less cash received within working capital (the TEAK Acquisition). The assets acquired, which we refer to as the SouthTX assets, include the following gas gathering and processing facilities in the Eagle Ford shale region of south Texas:

- the Silver Oak I plant, which is a 200 MMCFD cryogenic processing facility;
- a second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, expected to be in service the second quarter of 2014;
- 265 miles of primarily 20-24 inch gathering and residue lines;
- approximately 275 miles of low pressure gathering lines;
- a 75% interest in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle), which owns a 62 mile, 24-inch gathering line;
- a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford), which owns a 45 mile 16-inch gathering pipeline; a 71 mile, 24-inch gathering line; and a 50 mile residue pipeline; and
- a 50% interest in T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen), which owns a cogeneration facility.

Gas Plant Expansion Projects

In December 2012, we announced construction of the Stonewall Plant, a 120 MMCFD cryogenic processing plant which is expandable to a processing capacity of 200 MMCFD. Construction of the plant continues and we expect it to be placed into service early in second quarter 2014 with an initial processing capacity of 120 MMCFD. The SouthOK system name-plate processing capacity will increase to 500 MMCFD upon initial completion of the Stonewall Plant.

On April 12, 2013, we placed into service a new 200 MMCFD cryogenic processing plant, known as the Driver Plant, in our WestTX system in the Permian Basin of Texas, increasing the name-plate processing capacity of our WestTX system to 455 MMCFD.

As part of the TEAK Acquisition in May 2013, we acquired a 200 MMCFD cryogenic processing plant, known as the Silver Oak II Plant, which is under construction. We expect the plant to be placed into service during the second quarter 2014, increasing the SouthTX system name-plate processing capacity to 400 MMCFD.

On July 15, 2013, we announced plans to construct a new 200 MMCFD cryogenic processing plant, known as the Edward Plant, in our WestTX system. The plant is expected to be placed into service in late 2014, which will increase our WestTX system name-plate processing capacity to 655 MMCFD.

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On October 24, 2013, we announced plans to expand the gathering footprint of our WestTX system. This project includes the laying of a high pressure gathering line into Martin County, Texas, as well as adding incremental compression and processing to utilize WestTX s existing assets, including installation of the Edward Plant.

In addition, on October 24, 2013, we announced plans to expand the gathering infrastructure of the Velma system located in the Woodford Shale Region of southern Oklahoma and connect it to the Arkoma system, which is also located in the Woodford Shale Region. The expansion of our Velma system and connection with our Arkoma system will accommodate the increased demand for processing capacity behind the Velma system, where the emerging South Central Oklahoma Oil Province (SCOOP) play has attracted significant producer interest. Since the Velma system is nearly fully utilized and the Arkoma system capacity is being increased by 120 MMCFD with the first quarter 2014 start-up of the Stonewall Plant, as discussed below, the planned connection between the Velma and Arkoma systems will offer us more operational flexibility and help us better utilize our processing capacity across both systems. We expect to complete the connection of the two systems during the third quarter 2014. We now refer to the combined Velma and Arkoma systems as SouthOK.

Financing

On February 11, 2013, we issued $650.0 million of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.3 million and utilized the proceeds to redeem our outstanding 8.75% senior unsecured notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of the outstanding indebtedness under our revolving credit facility. On January 9, 2014 we consummated an exchange offer for the 5.875% Senior Notes.

Prior to issuance of the 5.875% Senior Notes and in anticipation thereof, on January 28, 2013, we commenced a cash tender offer for any and all of our outstanding $365.8 million 8.75% Senior Notes. In February 2013, we accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation. We also redeemed all the 8.75% Senior Notes not purchased in connection with the tender offer.

On April 17, 2013, we sold 11,845,000 of our common units in a registered public offering at a price of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. We also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest. We used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition.

On May 7, 2013, we completed a private placement of $400.0 million of our Class D convertible preferred units (Class D Preferred Units) to third party investors, at a negotiated price per unit of $29.75 for net proceeds of $397.7 million. We also received a capital contribution from the General Partner of $8.2 million to maintain its 2.0% general partnership interest. We used the proceeds to fund a portion of the purchase price of the TEAK Acquisition.

On May 10, 2013, we issued $400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes) in a private placement transaction. The 4.75% Senior Notes were issued at par. We received net proceeds of $391.2 million and utilized the proceeds to repay a portion of our outstanding indebtedness under the revolving credit facility as part of the TEAK Acquisition. On January 9, 2014 we consummated an exchange offer for the 4.75% Senior Notes.

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General

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating).

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK, and WestTX operations, which are comprised of natural gas gathering, processing and treating assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas; (2) natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee; and (3) through the year ended December 31, 2011, the revenues and gain on sale related to our former 49% interest in Laurel Mountain Midstream, LLC (Laurel Mountain). Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas.

Our Gathering and Processing operations own, have interests in, and operate fourteen natural gas processing plants with aggregate capacity of approximately 1,500 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 11,200 miles of active natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. Our gathering systems gather natural gas from oil and natural gas wells and central delivery points and deliver this gas to processing plants and third-party pipelines.

Our Gathering and Processing operations are all located in or near areas of abundant and long-lived natural gas production, including the Golden Trend, Mississippian Limestone and Hugoton Field in the Anadarko Basin; the Woodford Shale; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin; the Eagle Ford Shale; and the Barnett Shale. Our gathering systems are connected to receipt points consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. We believe we have significant scale in each of our primary service areas. We provide gathering, processing and treating services to the wells connected to our systems primarily under long-term contracts. As a result of the location and capacity of our gathering, processing and treating assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Our Transportation and Treating segment consists of the Gas Treating operations and a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG). The Gas Treating operations own seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas. The Gas Treating operations are located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation.

In connection with the TEAK Acquisition (see Recent Developments), we reviewed the acquired assets to determine the proper alignment of these assets within the existing reportable segments. The gas gathering and processing facilities acquired, along with their related assets, are included in the Gathering and Processing segment since the operating activities of the acquired assets are similar to the operating activities of other assets within that segment.

We intend to continue to expand our business through strategic acquisitions and internal growth projects in efforts to increase distributable cash flow.

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Business Strategy

The primary business objective of our management team is to provide stable long-term cash distributions to our unitholders. Our business strategies focus on creating value for our unitholders by providing efficient operations; focusing on prudent growth opportunities via organic growth projects and external acquisitions; and maintaining a commodity risk management program in an attempt to manage our commodity price exposure. We intend to accomplish our primary business objective by executing on the following:

Expanding operations through organic growth projects and increasing the profitability of our existing assets. In many cases, we can expand our gathering pipelines and processing plants and, to the extent we have excess capacity, we can connect and process new supplies of natural gas with minimal additional capital requirements, also increasing plant efficiency and economics. We plan to access new supplies of natural gas by providing excellent service to our existing customers; aggressively marketing our services to new customers; and prudently expanding our existing infrastructure to ensure our services can meet the needs of potential customers. Our recent construction of the Driver processing facility, our current construction of the Silver Oak II and Stonewall plants and our announced construction of the Edward plant and connection of the Arkoma and Velma systems are examples of executing this strategy. Other opportunities include pursuing relationships with new producers; eliminating pipeline bottlenecks; reducing operating line pressures; and focusing on reduction of pipeline losses along our gathering systems.

Pursuing strategic acquisitions. We continue to pursue strategic acquisitions that leverage our existing asset base, employees and customer relationships. The recent TEAK Acquisition is an example of executing this strategy (see Recent Developments). In the past, we have pursued opportunities in certain regions outside of our current areas of operation and will continue to do so when these options make sense economically and strategically.

Reducing the sensitivity of our cash flows through prudent economic risk management and contract arrangements. We attempt to structure our contracts in a manner that allows us to achieve our target rates of return while reducing our exposure to commodity price movements. We actively review our contract mix and seek to optimize a balance of cash flow stability with attractive economic returns. Our commodity price risk management activities are designed to reduce the effect of commodity price volatility related to future sales of natural gas, NGLs and condensate, while allowing us to meet our debt service requirements; fund our maintenance capital program; and meet our distribution objectives.

Maintaining our financial flexibility. We intend to maintain a capital structure in which we do not significantly exceed equal amounts of debt and equity on a long-term basis while not jeopardizing our ability to achieve our other business strategies as listed above. We seek to maintain a minimum total liquidity of at least $100.0 million; a ratio of debt to capital of not more than 50%; and a ratio of long-term debt to trailing 12-month EBITDA of less than 4x. We believe our revolving credit facility, our ability to issue additional long-term debt or common units and our relationships with our partners provide us with the ability to achieve this strategy. We will also consider alternative financing, joint venture arrangements and other means that allow us to achieve our business strategies while continuing to maintain an acceptable capital structure.

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The Midstream Natural Gas Gathering and Processing Industry

The midstream natural gas gathering and processing industry is characterized by regional competition based on the proximity of gathering systems and processing plants to producing natural gas wells.

The natural gas gathering process begins with the drilling of wells into natural gas or oil bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of pipelines that collect natural gas from points near producing wells and transport gas and other associated products to plants for processing and treating and to larger pipelines for further transportation to end-user markets. Gathering systems are operated at design pressures via pipe size and compression that help maximize the total throughput from all connected wells.

While natural gas produced in some areas does not require treating or processing, natural gas produced in other areas is not suitable for long-haul pipeline transportation or commercial use and must be compressed, gathered via pipeline to a central processing facility, potentially treated and then processed to remove certain hydrocarbon components, such as NGLs and other contaminants, that would interfere with pipeline transportation or the end use of the natural gas. Natural gas treating and processing plants generally treat (remove carbon dioxide and hydrogen sulfide) and extract the NGLs, enabling the treated, dry gas (commercially marketable BTU content) to meet pipeline specification for long-haul transport to end users. After being separated from natural gas at the processing plant, the mixed NGL stream, commonly referred to as y-grade or raw mix, is typically transported in pipelines to a centralized facility for fractionation into discrete NGL purity products: ethane, propane, normal butane, isobutane, and natural gasoline. Generally NGL transportation agreements generate revenue based on a fee per unit of volume transported.

Contracts and Customer Relationships

Our principal revenue is generated from the gathering, processing and treating of natural gas; the sale of natural gas, NGLs and condensate; the transportation of NGLs; and the leasing of gas treating facilities. Primary contracts are Fee-Based, POP and Keep-Whole (see Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations). For the year ended December 31, 2013, ONEOK Hydrocarbon, L.P. (ONEOK); Tenaska Marketing Ventures, Inc.; and DCP NGL Services, LLC, a subsidiary of DCP Midstream, LLC (DCP) accounted for approximately 29%, 17% and 14%, respectively, of our consolidated total third-party revenues, respectively, excluding the impact of all financial derivative activity, with no other single customer accounting for more than 10% for this period.

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Our Gathering and Processing Operations

We own and operate approximately 11,200 miles of intrastate natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. We also own and operate fourteen natural gas processing facilities and one treating facility located in Oklahoma and Texas. Our gathering, processing and treating assets service long-lived natural gas regions, including the Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas. Our systems gather natural gas from oil and natural gas wells; process the raw natural gas into residue gas by extracting NGLs and removing impurities; and transport natural gas to interstate and public utility pipelines for delivery to customers. Our gathering, processing and treating systems have receipt points consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. Our gathering systems interconnect with interstate and intrastate natural gas pipelines operated by Atmos Energy Corporation; El Paso Natural Gas Company; Enogex, LLC; Enterprise Intrastate, LLC; Kinder Morgan Tejas Pipeline LLC; Natural Gas Pipeline Company of America; Northern Natural Gas Company; ONEOK Gas Transportation, LLC; Panhandle Eastern Pipe Line Company, LP; Southern Star Central Gas Pipeline, Inc.; Tennessee Gas Pipeline Company, LLC; Texas Eastern Transmission; Transcontinental Gas Pipe Line; and APL SouthTex Transmission Company, L.P., our Section 311; intrastate pipeline (see Pipeline Safety and Other Regulations Transmission Pipeline Regulation). Our processing facilities are connected to NGL pipelines operated by Chaparral Pipeline Company, L.P.; Crosstex Energy, L.P.; DCP; Lone Star NGL LLC; ONEOK and WTLPG. Construction is underway to connect our SouthTX processing facilities to an NGL pipeline owned by TexStar Midstream Services, L.P.

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Gathering Systems

SouthOK. SouthOK consists of the Velma system and the Arkoma systems, which will be connected during 2014 through installing approximately 55 miles of pipeline between the systems. The connection between the Velma and Arkoma areas is anticipated to be completed by third quarter of 2014. (see Recent Developments).

The Velma gathering system is located in the Golden Trend and near the Woodford Shale areas of southern Oklahoma. The gathering system has approximately 1,200 miles of active pipelines. The primary producers on the Velma gathering system include Marathon Oil Company; Merit Management Partners; and XTO Energy, Inc. (XTO).

The Arkoma gathering systems are located in the Woodford Shale in southern Oklahoma. The gathering systems have approximately 100 miles of active pipeline. The primary producers on the Arkoma gathering system include Atoka Midstream, LLC and Vanguard Natural Resources, LLC.

SouthTX. The SouthTX gathering systems were acquired as part of the TEAK Acquisition (see Recent Developments) and are located in the Eagle Ford Shale in southern Texas. The gathering systems have approximately 500 miles of active pipeline with receipt points consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. Our SouthTX assets also include a 75% interest in T2 LaSalle, which has approximately 60 miles of active gathering pipeline; and a 50% interest in T2 Eagle Ford, which has approximately 116 miles of active gathering pipeline. The primary producers on the SouthTX gathering system include Statoil Natural Gas LLC (Statoil) and Talisman Energy USA Inc. (Talisman).

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WestOK. The WestOK gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. The gathering system has approximately 5,700 miles of active natural gas gathering pipelines. The primary producers on the WestOK gathering system include Chesapeake Energy Corporation and SandRidge Exploration and Production, LLC (Sandridge).

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WestTX. The WestTX gathering system, which we operate and in which we have an approximate 72.8% ownership, has approximately 3,600 miles of active natural gas gathering pipelines located across seven counties within the Permian Basin in West Texas. Pioneer Natural Resources Company (NYSE: PXD) (Pioneer), the largest active driller in the Spraberry Trend and a major producer in the Permian Basin, owns the remaining interest in the WestTX system. The primary producers on the WestTX gathering system include COG Operating, LLC; Laredo Petroleum, Inc.; and Pioneer Natural Resources USA, Inc.

Barnett. The Barnett Shale gas gathering system and related assets are located in Tarrant County, Texas. The system consists of 20 miles of gathering pipeline. The Barnett gas gathering system is used to facilitate gathering the natural gas production of our affiliate, Atlas Resource Partners, L.P. (ARP).

Tennessee. The Tennessee gathering systems are located in the Appalachian Basin. The gathering systems have approximately 70 miles of natural gas gathering pipelines. A portion of the natural gas we gather in Tennessee is derived from wells operated by ARP. In addition, we gather and transport gas for other natural gas producers in the area.

Processing Plants

SouthOK. The Velma processing facility, located in Stephens County, Oklahoma, is comprised of two separate plants, including the original Velma cryogenic plant with a natural gas name-plate capacity of approximately 100 MMCFD and a 60 MMCFD cryogenic plant (the V-60 plant), which was placed in service in July 2012. The V-60 plant supports volumes from XTO and other producers in the area who are looking to take advantage of the high NGL content gas in the Woodford shale. The Arkoma facility processes and treats natural gas through three separate processing plants at the Atoka, Coalgate and Tupelo processing facilities and the East Rockpile treating facility. These facilities also

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process natural gas gathered by MarkWest Oklahoma Gas Company, LLC (MarkWest). The Atoka facility is a 20 MMCFD cryogenic plant in Atoka County, Oklahoma, which started operations in November 2006. The Coalgate facility is an 80 MMCFD cryogenic plant in Coal County, Oklahoma, which started operations in September 2007. The Atoka and Coalgate facilities are owned by Centrahoma, which we operate, and in which we have a 60% ownership interest; the remaining 40% ownership interest is held by MarkWest. The Tupelo facility is a wholly-owned 120 MMCFD cryogenic plant in Coal County, Oklahoma, which started operations in December 2011. The East Rockpile facility is a 250 GPM amine treating plant in Pittsburg County, Oklahoma, which started operations in June 2007. To facilitate increased Woodford shale production, Centrahoma is constructing a new 200 MMCFD cryogenic processing plant, initially equipped to process 120 MMCFD, known as the Stonewall plant, which is located near the Coalgate and Tupelo facilities and is expected to be in service in the first quarter of 2014. The Stonewall plant will initially increase the SouthOK aggregate processing name-plate capacity to approximately 500 MMCFD. We deliver and/or sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the Velma and Arkoma facilities and sell NGL production to ONEOK.

SouthTX. The SouthTX system, which was acquired as part of the TEAK Acquisition (see Recent Developments), processes natural gas through the Silver Oak I processing facility. The Silver Oak I facility is a 200 MMCFD cryogenic plant located in Bee County, Texas, which started operations in 2012. A second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, is scheduled to be placed into service during the second quarter of 2014. Our SouthTX assets also include a 50% interest in T2 EF Co-Gen, which owns a cogeneration facility. We transport and deliver natural gas to various pipelines at the outlet of our Section 311 intrastate transportation pipeline (see Pipeline Safety and Other Regulations Transmission Pipeline Regulation). We deliver and/or sell natural gas to various third parties, including marketing companies, and sell NGL production to Crosstex Energy L.P. and DCP.

WestOK. The WestOK system processes natural gas through three separate plants at the Waynoka I and II and Chester facilities, which are active cryogenic natural gas processing plants; and one plant at the Chaney Dell facility, which is a refrigeration facility. The WestOK system s processing operations have total name-plate capacity of approximately 458 MMCFD. The Waynoka I processing facility, a 200 MMCFD plant located in Woods County, Oklahoma, began operations in 2006. The Waynoka II processing facility, a 200 MMCFD cryogenic plant in Woods County, Oklahoma, began operations in September 2012. The Chester processing facility, a 28 MMCFD plant located in Woodward County, Oklahoma, began operations in 1981. The Chaney Dell processing facility, a 30 MMCFD refrigeration plant in Woods County, Oklahoma, began operations in January 2012. The oil wells being drilled in the Mississippian play are producing large amounts of associated gas high in NGL content, adding economic value for both the producers and processors like us. We deliver and/or sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the Waynoka, Chester and Chaney Dell facilities and sell NGL production to ONEOK.

WestTX. The WestTX system processes natural gas through four separate plants at the Consolidator, Driver, Midkiff and Benedum processing facilities. The Consolidator plant is a 150 MMCFD cryogenic plant in Reagan County, Texas, which started operations in 2009. The Driver plant is a 200 MMCFD cryogenic plant in Midland County, Texas, which started operations in April 2013. The Benedum plant is a 45 MMCFD cryogenic plant in Upton County, Texas. The Midkiff plant is a 60 MMCFD cryogenic plant located at the same site as our Consolidator plant. Our WestTX processing operations have an aggregate processing name-plate capacity of approximately 455 MMCFD. To facilitate increased Spraberry production, we are constructing a new 200 MMCFD cryogenic processing plant, known as the Edward plant, which is expected to be in service in the second half of 2014. The additional plant will increase the WestTX aggregate processing name-plate capacity to approximately 655 MMCFD. We deliver and/or sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the WestTX facilities and sell NGL production to DCP.

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Natural Gas Supply

We have natural gas purchase, gathering and processing agreements with approximately 600 producers. These agreements provide for the purchase or gathering of natural gas under Fee-Based, POP or Keep-Whole arrangements. Many of the agreements provide for compression, processing and/or low volume fees. Producers generally provide, in-kind, their proportionate share of compressor and plant fuel required to gather the natural gas and to operate our processing plants. In addition, the producers generally bear their proportionate share of gathering system line loss and, except for Keep-Whole arrangements, bear natural gas plant shrinkage for the gas consumed in the production of NGLs.

We have long-term, service-driven relationships with our producing customers, who comprise some of the largest producers in our areas. Several of our top producers have contracts with primary terms running into 2020 and beyond. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions. On our WestTX system, we have a gas sales and purchase agreement with Pioneer with a term extending into 2022. The gas sales and purchase agreement requires all Pioneer wells within an area of mutual interest be dedicated to that system s gathering and processing operations in return for specified natural gas processing rates. Through this agreement, we anticipate we will continue to provide gathering and processing for the majority of Pioneer s wells in the Spraberry Trend of the Permian Basin. On our WestOK system, we have a contract with SandRidge with a term currently extending through 2017. As part of the agreement, SandRidge has agreed to dedicate the majority of its developed acreage covering the Mississippian Lime formation. On our SouthTX system, our primary producers, Talisman and Statoil, both have fixed-fee long term agreements with volume commitments extending into 2022. We believe that our relationships with these key producers will provide us with a competitive advantage in adding new natural gas supplies, retaining previously connected volumes and continuing to increase our scale and presence in our operating areas.

Natural Gas and NGL Marketing

We typically sell natural gas to purchasers downstream of our processing plants priced at various first-of-month indices as published in *Inside FERC*. Additionally we sell swing gas, which is natural gas sold on a daily basis at various *Platt s Gas Daily* midpoint prices. The SouthOK system has access to Enogex, LLC; MarkWest Energy Partners, LP s Arkoma Connector Pipeline; Natural Gas Pipeline Company of America; ONEOK Gas Transportation, LLC; and Southern Star Central Gas Pipeline, Inc. Through its Section 311 intrastate transmission pipeline, the SouthTX system has access to Enterprise Intrastate, LLC; Kinder Morgan Tejas Pipeline LLC; Natural Gas Pipeline Company of America; Tennessee Gas Pipeline Company, LLC; Texas Eastern Transmission, LLC; and Transcontinental Gas Pipe Line. The WestOK system has access to Enogex LLC; Panhandle Eastern Pipe Line Company, LP; and Southern Star Central Gas Pipeline, Inc. The WestTX system has access to Atmos Energy Corporation; El Paso Natural Gas Company; Kinder Morgan Tejas Pipeline, LLC; and Northern Natural Gas Company.

We sell our NGL production at SouthOK and WestOK, to ONEOK under three separate agreements. The WestOK agreement has a term expiring in 2014; the Velma agreement within SouthOK has a term expiring at the end of 2016; and the Arkoma agreement within SouthOK has a term expiring in 2024. We sell our NGL production at SouthTX, WestTX and the Chaney Dell plant in WestOK to DCP. We also sell our NGL production at SouthTX to Crosstex Energy Services, L.P. We have signed agreements with DCP to sell our NGL production from our WestOK and Velma processing facilities upon

the expiration of each of the ONEOK agreements. The DCP agreements each have a term of fifteen years. All NGL agreements are priced at the average daily Oil Price Information Service (or OPIS) price for the month for the selected market, subject to reduction by a Base Differential for transportation and fractionation fees and, if applicable, quality adjustment fees.

Condensate collected at the SouthOK gas plants and gathering systems is currently sold to EnerWest Trading Company, LLC and Enterprise Products Partners, L.P. Condensate collected at the SouthTX gas plant and gathering systems is currently sold to High Sierra Energy, L.P. and Superior Crude Gathering, Inc. Condensate collected at the WestOK plants and gathering systems is currently sold to JP Energy Partners, L.P. and Plains Marketing, L.P. Condensate collected at the WestTX plants and gathering systems is currently sold to Occidental Energy Marketing, Inc. and Plains Marketing, L.P.

Commodity Risk Management

Our gathering and processing operations are exposed to certain commodity price risks. These risks result from either taking title to natural gas, NGLs and condensate, or being obligated to purchase natural gas to satisfy contractual obligations with certain producers. We attempt to mitigate a portion of these risks through a commodity price risk management program, which employs a variety of financial tools. The resulting combination of the underlying physical business and the commodity price risk management program attempts to convert the physical price environment that consists of floating prices to a risk-managed environment characterized by (1) fixed prices; (2) floor prices on products where we are long the commodity; and (3) ceiling prices on products where we are short the commodity. There are also risks inherent within risk management programs, including, among others, deterioration of the price relationship between the physical and financial instrument; and changes in projected physical volumes.

We are exposed to commodity price risks when natural gas is purchased for processing. The amount and character of this price risk is a function of our contractual relationships with natural gas producers or, alternatively, a function of cost of sales. We are therefore exposed to price risk at a gross profit level rather than at a revenue level. These cost-of-sales or contractual relationships are generally of two types:

- POP: requires us to pay a percentage of revenue to the producer. This generally results in our having a net long physical position for natural gas and NGLs.

- Keep-Whole: generally requires us to deliver the same quantity of natural gas (measured in BTU s) at the delivery point as we received at the receipt point; any resulting NGLs produced belong to us, resulting in having a net long physical position for NGLs and a net short physical position for natural gas.

We manage the positions for natural gas on a net basis, netting our physical long positions against our physical short positions. Normally we are in a net long position on our natural gas.

We manage a portion of these risks by using fixed-for-floating swaps, which result in a fixed price for the products we buy or sell; or by utilizing the purchase of put or call options, which result in floor prices or ceiling prices for the products we buy or sell. We utilize natural gas swaps and options to manage our natural gas price risks. We utilize NGL and crude oil swaps and options to manage our NGL and condensate price risks.

We generally realize gains and losses from the settlement of our derivative instruments at the same time we sell the associated physical residue gas or NGLs. We also record the unrealized gains and losses for the mark-to-market valuation of derivative instruments prior to settlement. We determine gains

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or losses on open and closed derivative transactions as the difference between the derivative contract price and the physical price. This mark-to-market methodology uses (1) daily closing New York Mercantile Exchange (NYMEX) prices; (2) third party sources; and/or (3) an internally-generated algorithm, utilizing third party sources, for commodities not traded on an open market. To ensure these derivative instruments will be used solely for managing price risks and not for speculative purposes, we have established a committee to review our derivative instruments for compliance with our policies and procedures.

For additional information on our derivative activities, please see Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Our Transportation, Treating and Other Operations

Our Transportation and Treating operations consist of a 20% interest in WTLPG and seventeen contract gas treating facilities located in Arkansas, Louisiana, Oklahoma and Texas.

West Texas LPG. WTLPG owns an approximately 2,200 mile common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. Revenues are derived from fee-based transportation services and are a function of the volume of NGLs transported. Revenues are not directly dependent upon the value of NGLs, thus commodity price risk is limited.

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Gas Treating. Our gas treating facilities include fifteen skid-mounted amine treating plants of various sizes with total capacity of 1,262 GPM and two propane refrigeration plants with total capacity of 27 MMCFD. The plants are currently operating in the Delaware Basin, Granite Wash, Haynesville, Eagle Ford, Woodford and Fayetteville Shale, or are in inventory awaiting deployment. Key customers include Crestwood Arkansas Pipeline, LLC; TPF II East Texas Gathering, LLC; and XTO. Revenues are derived from fee-based contract services and are a function of the capacity of the treating plant. Revenues are not directly dependent upon the value of the natural gas that is treated and thus commodity price risk is limited.

Competition

Acquisitions. We have encountered competition in acquiring midstream assets owned by third parties. In several instances, we submitted bids in auction situations and in direct negotiations for the acquisition of such assets and we were either outbid by others or we were unwilling to meet the sellers expectations. In the future, we expect to encounter equal, if not greater, competition for the acquisition of midstream assets.

Gathering and Processing. In our Gathering and Processing segment, we compete for the acquisition of well connections with several other gathering/processing operations. These operations include plants and gathering systems operated by Access Midstream Partners, LP; Caballo Energy, LLC; Carrera Gas Company; Crosstex Energy Services, L.P.; DCP; Devon Energy Corporation; Duke Energy Corporation; Energy Transfer Partners, L.P.; Enable Midstream Partners, L.P.; Enterprise Products Partners, L.P.; Howard Energy Partners, LLC; Kinder Morgan Energy Partners, L.P.; Lumen Midstream Partners, LLC; Mustang Fuel Corporation; ONEOK Field Services Company, LLC; Regency Energy Partners, L.P.; SemGas, L.P.; Southcross Energy Partners, L.P.; Superior Pipeline Company, LLC; Targa Resources Partners LP; TexStar Midstream Services, L.P.; and West Texas Gas, Inc.

We believe the principal factors upon which competition for new well connections is based are:

- the price received by an operator or producer for its production after deduction of allocable charges, principally the use of the natural gas to operate compressors;
- the quality and efficiency of the gathering systems and processing plants that will be utilized in delivering the gas to market;
- the access to various residue markets that provides flexibility for producers and ensures the gas will make it to market; and
- the responsiveness to a well operator s needs, particularly the speed at which a new well is connected by the gatherer to its system.

We believe that we have good relationships with operators connected to our system and that we present an attractive alternative for producers. However, if we cannot compete successfully through pricing or services offered, we may be unable to obtain new well connections.

Transportation, Treating and Other. In our Transportation and Treating segment, we compete with other intrastate and interstate pipeline companies that transport NGLs in the southwestern region of the United States. These operations include NGL pipelines operated by DCP; Enterprise Partners, L.P.; Lonestar NGL, LLC; and ONEOK Partners, L.P. We also compete for gas treating services provided on gas gathering lines, including gas treating services provided by Allied Equipment, Inc.; Kinder Morgan Energy Partners, L.P.; Spartan Energy Partners LLC; TransTex Hunter, LLC; and Zephyr Gas Services LLC.

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The factors that typically affect our ability to compete for NGL supplies and/or gas treating services are:

- fees charged under our contracts;
- the quality and efficiency of our operations;
- our responsiveness to a customer s needs; and
- with respect to transportation services, location of our transportation systems relative to our competitors.

Seasonality

Our business is affected by seasonal fluctuations in commodity prices. Sales volumes are also affected by various factors such as fluctuating and seasonal demands for products and variations in weather patterns from year to year. Generally, natural gas demand increases during the winter months and decreases during the summer months. Freezing conditions can disrupt our gathering process, which could adversely affect our operating results.

Environmental Matters and Regulations

The operation of pipelines, plant and other facilities for gathering, compressing, treating, processing, or transporting natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and 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 by:

- restricting the way waste disposal is handled;
- limiting or prohibiting construction and operating activities in sensitive areas such as wetlands, coastal regions, non-attainment areas, tribal lands or areas inhabited by endangered species;
- requiring the installation of expensive pollution control equipment;
- requiring remedial measures to reduce, and/or respond to releases of pollutants or hazardous substances by our operations or attributable to former operators;
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and

imposing substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where pollutants or wastes have been disposed or otherwise released. Neighboring landowners and other third parties can file claims for personal injury or property damage allegedly caused by noise and/or the release of pollutants or wastes into the environment. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress, federal and state agencies frequently enact new, and revise existing, environmental laws and regulations, and any new laws or changes to existing laws that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs.

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We believe our operations are in substantial compliance with applicable environmental laws and regulations and compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, 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. Moreover, we cannot ensure that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions, will not cause us to incur significant costs.

Environmental laws and regulations that could have a material impact on our operations include the following:

Endangered Species Act. The federal Endangered Species Act (ESA) restricts activities that may affect endangered or threatened species or their habitats. Endangered species, including without limitation, the American Burying Beetle, which are located in various states in which we operate. If endangered species are located in areas where we propose to construct new gathering or processing facilities, such work could be prohibited or delayed or expensive mitigation may be required. Existing laws, regulations, policies and guidance relating to protected species may also be revised or reinterpreted in a manner that further increases our construction and mitigation costs or restricts our construction activities. Additionally, construction and operational activities could result in inadvertent impact to habitats of listed species and could result in alleged takings under the ESA, exposing us to civil or criminal enforcement actions and fines or penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by completion of the agency s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations or plan to construct pipelines or facilities could cause us to incur increased costs arising from species protection measures or could result in delays in the construction of our facilities or limitations on our customer s exploration and production activities, which could have an adverse impact on demand for our midstream operations.

Hazardous Waste. The Solid Waste Disposal Act, including the Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and the disposal of non-hazardous wastes. Under the auspices of the EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil and natural gas constitute solid wastes , which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as solid waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

We believe our operations are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes to be significant, any more stringent regulation of natural gas and oil exploration and production wastes could increase our costs to manage and dispose of such wastes.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered under the statute to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years were used for the measurement, gathering, field compression and processing of natural gas. Although we believe that we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by them or on or under other locations, including off-site locations, where such substances have been taken for disposal. There may be evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. However, none of these spills or releases appear to be material to our financial condition and we believe all of them have been or will be appropriately remediated. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, certain storage vessels and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of customer compliance to the point where demand for natural gas is affected. Various air quality regulations are periodically reviewed by the EPA and are amended as deemed necessary. The EPA may also issue new regulations based on changing environmental concerns.

In 2012, specific federal regulations applicable to the natural gas industry were finalized under the New Source Performance Standards (NSPS) program along with National Emissions Standards for Hazardous Air Pollutants (NESHAP). These new regulations impose additional emissions control requirements and practices on our operations. Some of our facilities may incur additional capital costs in order to comply with new emission limitations. These regulations may increase the costs of compliance for some facilities. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that our operations are in substantial compliance with the requirements of the Clean Air Act.

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While we will likely be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions, we believe 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 other similarly situated companies.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state. These permits may require pretreatment of produced waters before discharge. Compliance with such permits and requirements may be costly. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The Clean Water Act also requires specified facilities to maintain and implement spill prevention, control and countermeasure plans and to take measures to minimize the risks of petroleum spills. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for failure to obtain a permit or non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe our operations are in substantial compliance with the requirements of the Clean Water Act.

OSHA and other regulations. We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans and can result in death. A portion of the gas processed at our Velma gas plant contains high levels of hydrogen sulfide, and we employ numerous safety precautions at the system to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

Chemicals of Interest. We operate several facilities registered with the U.S. Department of Homeland Security, or DHS, in order to identify the quantities of various chemicals stored at the sites. The liquid hydrocarbons recovered and stored as a result of facility processing activities, and various chemicals utilized within the processes, have been identified and registered with DHS. These registration requirements for *Chemical of Interest* were first promulgated by DHS in 2008 and we are currently in compliance with the Department s requirements. None of our affected facilities are considered high security risks by DHS at this time and no specific security plans for such per DHS regulations are required.

Greenhouse gas regulation and climate change. To date, legislative and regulatory initiatives relating to greenhouse gas emissions have not had a material impact on our business. However, Congress has been actively considering climate change legislation. More directly, the EPA has begun regulating greenhouse gas emissions under the federal Clean Air Act. In response to the Supreme Court s decision in Massachusetts V. EPA, 549 U.S. 497 (2007) (holding that greenhouse gases are air pollutants covered by the Clean Air Act), the EPA made a final determination that greenhouse gases endangered public health and welfare, 74 Fed. Reg. 66,496 (December 15, 2009). This finding led to the regulation of greenhouse gases under the Clean Air Act. Currently, the EPA has promulgated two rules that will impact our business.

First, the EPA promulgated the so-called Tailoring Rule which established emission thresholds for greenhouse gases under the Clean Air Act permitting programs, 75 Fed. Reg. 31514 (June 3, 2010). Both the federal preconstruction review program (Prevention of Significant Deterioration, or PSD) and the operating permit program (Title V) are now implicated by emissions of greenhouse gases. These programs, as modified by the Tailoring Rule, could require some new facilities to obtain a PSD permit depending on the size of the new facilities. Likewise, existing facilities could be required to obtain a PSD permit if modification projects are significant. In addition, existing facilities as well as new facilities that exceed the emissions thresholds could be required to obtain Title V operating permits.

Second, the EPA finalized its Mandatory Reporting of Greenhouse Gases rule in 2009, 74 Fed. Reg. 56,260 (October 30, 2009). Subsequent revisions, additions, and clarification rules were promulgated, including a rule specifically addressing the natural gas industry. These rules require certain industry sectors that emit greenhouse gases above a specified threshold to report greenhouse gas emissions to the EPA on an annual basis. This rule imposes additional obligations on us to determine whether the greenhouse gas reporting applies and if so, to calculate and report greenhouse gas emissions.

There are also ongoing legislative and regulatory efforts to encourage the use of cleaner energy technologies. While natural gas is a fossil fuel, it is considered to be more benign, from a greenhouse gas standpoint, than other carbon-based fuels, such as coal or oil. Thus future regulatory developments could have a positive impact on our business to the extent that they either decrease the demand for other carbon-based fuels or position natural gas as a favored fuel.

In addition to domestic regulatory developments, the United States is a participant in multi-national discussions intended to deal with the greenhouse gas issue on a global basis. To date, those discussions have not resulted in the imposition of any specific regulatory system, but such talks are continuing and may result in treaties or other multi-national agreements that could have an impact on our business. Currently, some scientific and international organizations believe that methane, a greenhouse gas inadvertently emitted from our operations, has a higher global warming potential than previously recognized. The EPA may amend regulations to reflect this change. If so, the change would make it more likely that some of our operations would be subject to PSD and Title V permitting requirements.

Finally, the scientific community continues to engage in a healthy debate as to the impact of greenhouse gas emissions on planetary conditions. For example, such emissions may be responsible for increasing global temperatures, and/or enhancing the frequency and severity of storms, flooding and other similar adverse weather conditions. We do not believe that these conditions are having any material current adverse impact on our business, and we are unable to predict at this time, what, if any, long-term impact such climate effects would have.

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Pipeline Safety and Other Regulations

Pipeline Safety. Some of our natural gas pipelines are subject to regulation by the U.S. Department of Transportation, or DOT, under the pipeline safety laws, 49 U.S.C. §§ 60101 et seq. The pipeline safety laws authorize DOT to regulate pipeline facilities and persons engaged in the transportation by pipeline of gas, i.e., natural gas, flammable gas, or gas that is toxic or corrosive, and hazardous liquids, i.e., petroleum or petroleum products, including NGLs, and other designated substances that pose an unreasonable risk to life or property when transported in liquid state. The DOT Secretary has delegated that authority to one of the Department s modal administrations, the Pipeline and Hazardous Material Safety Administration, or PHMSA. Acting primarily through the Office of Pipeline Safety, or OPS, PHMSA administers the national regulatory program to ensure the safety of transportation-related gas and hazardous liquid pipeline facilities.

As part of that national program, PHMSA has established minimum federal safety standards for the design, construction, testing, operation, and maintenance of gas and hazardous liquid pipeline facilities. These safety standards apply to most pipeline facilities in the United States, including gathering lines, transmission lines, and distribution lines, and are the only safety requirements that apply to interstate pipeline facilities. PHMSA has also promulgated a series of reporting requirements for operators of gas and hazardous liquid pipeline facilities, as well as provisions for establishing the qualification of pipeline personnel and requirements for managing the integrity of gas transmission and distribution lines and certain hazardous liquid pipelines. To ensure compliance with these provisions, OPS performs pipeline safety inspections and has the authority to initiate enforcement actions, which can lead to the assessment of administrative civil penalties of up to $200,000 per day, per violation, not to exceed $2,000,000 for any related series of violations.

PHMSA also oversees a program that allows the states to submit an annual certification to regulate intrastate pipeline facilities. States that participate in the program can apply additional or more stringent safety standards to the pipeline facilities under their certifications, so long as those standards are compatible with the minimum federal requirements. States can also enter into agreements with PHMSA to participate in the oversight of intrastate or interstate pipelines, primarily by performing inspections for compliance with preemptive federal safety standards. The Kansas Corporation Commission, the Oklahoma Corporation Commission, and the Texas Railroad Commission all participate in the federal gas pipeline safety program and have certification to regulate intrastate gas pipeline facilities. The Oklahoma Corporation Commission and the Texas Railroad Commission also have certification to regulate intrastate hazardous liquid pipeline facilities.

Our operations are required to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation and appropriate state authorities. We believe our pipeline operations are in substantial compliance with the federal pipeline safety laws and regulations and any state laws and regulations that apply to our pipeline facilities. However, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, the activities needed to ensure future compliance could result in additional costs.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was signed into law. The Act requires DOT and the U.S. Government Accountability Office to complete a number of reviews, studies, evaluations, and reports in preparation for potential rulemakings applicable to pipeline facilities. The issues addressed in these rulemaking provisions include, but are not limited to, the use of automatic or remotely-controlled shut-off valves on new or replaced transmission line facilities, modifying the requirements for pipeline leak detection systems, and expanding the scope of the pipeline integrity management requirements. PHMSA is considering these and other provisions in the Act and has sought public comment on changes to a number of regulations related to pipeline safety. On

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September 25, 2013, PHMSA issued a final rule implementing changes in its administrative procedures required by the Act, but the rulemaking process is continuing with respect to aspects of the Act related to pipeline safety regulations. At this time, we cannot predict what effect, if any, the future application of such regulations might have on our operations, but the midstream natural gas industry could be required as a result to incur additional capital expenditures and increased operating costs.

The state of Texas adopted House Bill 2982, effective on September 1, 2013. This bill requires the Texas Railroad Commission to establish safety standards and practices for gathering facilities and transportation activities. Before September 1, 2015, the Texas Railroad Commission must implement rules for the commission to investigate an accident, an incident, threats to public safety, and complaints related to operational safety and to require an operator to submit a plan to remediate an accident, incident, threat, or complaint; to require filing of reports with respect to any accidents, incidents, threats to public safety, or complaints, or to require operators to provide information requested by the commission.

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act of 1938, 15 U.S.C. § 717(b), exempts natural gas gathering facilities from the jurisdiction of FERC. We own a number of natural gas gathering lines in Kansas, Oklahoma and Texas that we believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated natural gas transportation facilities and federally unregulated natural gas gathering facilities is the subject of regular litigation, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC and the courts.

We are currently subject to state ratable take, common purchaser and/or similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. In particular, Kansas, Oklahoma and Texas have adopted 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 natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed or regulation by the Kansas Corporation Commission, the Oklahoma Corporation Commission or the Texas Railroad Commission become more active, our revenues could decrease. Collectively, any of these laws may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be, or may become, subject to 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 and 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.

Transmission Pipeline Regulation. We operate natural gas pipelines that extend from some of our processing plants to interconnections with both intrastate and interstate natural gas pipelines. Those facilities, known in the industry as plant tailgate pipelines, typically operate at transmission pressure levels and may transport pipeline quality natural gas. Because our plant tailgate pipelines are relatively short, we have treated them as stub lines, which are exempt from FERC s jurisdiction under the Natural Gas Act. FERC s treatment of the stub line exemption has varied over time, but, absent other factors, FERC generally limits the length of the lines that qualify for the stub line exemption.

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We own (in conjunction with Pioneer) and operate the Driver Residue Pipeline, a gas transmission pipeline extending from our Driver processing plant in West Texas just over ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. We have obtained a limited jurisdiction certificate of public convenience and necessity under the Natural Gas Act for the Driver Residue Pipeline. In the certificate order, among other things, FERC waived requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements. As such, the Driver Residue Pipeline is not currently subject to conventional rate regulation; to requirements FERC imposes on open access interstate natural gas pipelines; to the obligation to file and maintain a tariff; or to the obligation to conform to certain business practices and to file certain reports. If, however, we were to receive a *bona fide* request for firm service on the Driver Residue Pipeline from a third party, FERC would reexamine the waivers it has granted us and would require us to file for authorization to offer open access transportation under its regulations, which would impose additional costs upon us.

To the extent our plant tailgate pipelines do not, or may not in the future, qualify for the stub line exemption, we will consider whether we need to obtain FERC authorization to operate our tailgate pipelines or whether they can be reconfigured or otherwise modified to eliminate the possibility that they could be subject to FERC jurisdiction. If we conclude that FERC authorization is necessary, we would expect to seek regulatory treatment similar to the treatment FERC has accorded to the Driver Residue Pipeline. We cannot, however, assure you that FERC would agree to assert only limited jurisdiction. If FERC were to find that it must assert jurisdiction, our operating costs would increase and we could be subject to enforcement actions under the Energy Policy Act of 2005.

In 2013 we acquired the ownership interest of 50% of the capacity in a 50-mile long intrastate natural gas transmission pipeline, which extends from the tailgate of two natural gas processing plants located near Pettus, Texas to interconnections with existing intrastate and interstate natural gas pipelines near Refugio, Texas. The capacity is held by our affiliate, APL SouthTex Transmission Company LP (APL SouthTex Transmission), which is entitled to transport natural gas through its capacity on behalf of third parties to both intrastate and interstate markets. Because the jointly owned pipeline system was initially interconnected only with intrastate markets, each of the capacity holders qualified as an intrastate pipeline within the meaning of the Natural Gas Policy Act of 1978, or the NGPA and therefore are able to provide transportation of natural gas to interstate markets under Section 311 of the NGPA. Under Sections 311 and 601 of the NGPA, an intrastate pipeline may transport natural gas in interstate commerce without becoming subject to FERC regulation as a natural-gas company under the Natural Gas Act. Transportation of natural gas under Section 311 transportation service must be filed with FERC and must be shown to be fair and equitable. APL SouthTex Transmission has a Statement of Operating Conditions on file with FERC, and FERC has accepted the rates, which APL SouthTex Transmission s predecessor filed, as being in accordance with the fair and equitable standard. APL SouthTex Transmission is required to file, on or before November 6, 2017, a petition for approval of its then-existing rates, or to propose a new rate, applicable to NGPA Section 311 service.

NGL Pipeline Regulation. The transportation of crude oil, petroleum products and NGLs is subject in certain circumstances to regulation under the Interstate Commerce Act. Responsibility for the regulation of so-called oil pipelines now resides with the FERC. Rates charged for the interstate movement of crude oil, petroleum products and NGLs must be filed with FERC and are subject to FERC review and, under the Interstate Commerce Act, FERC has exclusive jurisdiction to determine whether oil pipelines interstate rates and terms of service are just, reasonable, and not unduly discriminatory. Pursuant to the Interstate Commerce Act, interstate oil pipeline rates can be challenged before FERC either by protest when they are initially filed or increased or by complaint for as long as they remain on file with FERC. FERC does not, however, regulate oil pipelines decisions to commence or terminate service or the construction of oil pipeline facilities. Individual states may regulate oil pipelines as utilities or as common carriers. As a general rule, neither FERC nor the states regulate oil pipelines that are purely proprietary and transport commodity only for the pipeline s owner.

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The Oklahoma Corporation Commission and Texas Railroad Commission both have authority to regulate rates for common carrier pipelines in their respective jurisdictions.

We own a 20% interest in WTLPG, which is a common carrier oil pipeline regulated by FERC under the Interstate Commerce Act and by the Texas Railroad Commission. The rates and terms and conditions of service that WTLPG may charge for interstate transmission of NGLs are specified in tariffs on file with FERC. Changes in the rates WTLPG charges may be made only in the manner specified in FERC regulations, and they are subject to challenge by protest by a shipper whose economic interest is directly affected by such rates. The rates and terms and conditions of service that WTLPG may charge for intrastate transmission of NGLs are specified in tariffs on file with the Texas Railroad Commission. The Texas Railroad Commission has not actively regulated common carrier rates, although it has the authority to do so. Rather, the Texas Railroad Commission relies on a complaint-based procedure to address issues associated with rates. If a complaint were filed or the Texas Railroad Commission were to begin actively regulating rates charged common carrier pipelines, the amounts WTLPG is entitled to charge could be affected.

We have an approximately fifteen mile NGL pipeline located in Oklahoma. This NGL pipeline is proprietary in nature and, as such, not subject to rate regulation by FERC or the Oklahoma Corporation Commission.

Transportation and Sales of Natural Gas and NGLs. A portion of our revenue is tied to the price of natural gas and NGLs. The wholesale price of natural gas and NGLs is not currently subject to federal regulation and, for the most part, is not subject to state regulation. Sales of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation of natural gas and NGLs are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting the segments of the natural gas industry, most notably interstate natural gas transportation companies that remain subject to FERC s jurisdiction. While FERC is less active in proposing changes in the manner in which it regulates the transportation of NGLs under the Interstate Commerce Act, it does nevertheless have authority to address the rates, terms and conditions under which NGLs are transported. FERC initiatives could, therefore, affect the transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of any regulatory changes that could result from such FERC initiatives on our operations.

Energy Policy Act of 2005. The Energy Policy Act contains numerous provisions relevant to the natural gas industry and to interstate natural gas pipelines in particular. Overall, the legislation attempts to increase supply sources by calling for various studies of the overall resource base and attempting to advantage deep water production on the Outer Continental Shelf in the Gulf of Mexico. However, the provisions of primary interest to us as an operator of natural gas gathering lines and sellers of natural gas focus on two areas: (1) infrastructure development; and (2) market transparency and enhanced enforcement. Regarding infrastructure development, the Energy Policy Act shortens depreciable life for gathering facilities; statutorily designates FERC as the lead agency for federal authorizations and permits relating to interstate natural gas pipelines; provides for the assembly of a consolidated record for all federal decisions relating to necessary authorizations and permits with respect to interstate natural gas pipelines; and provides for expedited judicial review of any agency action involving the permitting of such facilities and review by only the D.C. Circuit Court of Appeals of any alleged failure of a federal agency to act on a permit relating to an interstate natural gas pipeline by a deadline set by FERC as lead

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agency. Regarding market transparency and manipulation, the Energy Policy Act amended the Natural Gas Act to prohibit market manipulation and directs FERC to prescribe rules designed to encourage the public provision of data and reports regarding the price of natural gas in wholesale markets. In this regard, the Natural Gas Act and the Natural Gas Policy Act were also amended to increase monetary criminal penalties to $1,000,000 from the $5,000 amount specified under prior law and to add and increase civil penalty authority to be administered by FERC to $1,000,000 per day per violation without any limitation as to total amount.

Our Driver Residue Pipeline is subject to only limited regulation by FERC under the Natural Gas Act, and we anticipate that, if any other plant tailgate pipeline were to be held to be subject to FERC s Natural Gas Act jurisdiction, FERC would be likely to assert only limited jurisdiction over that line, as it has in the case of the Driver Residue Pipeline. Our APL SouthTex Transmission pipeline is subject to limited regulation of the interstate transportation services it provides under Section 311 of the NGPA. Accordingly, the provisions of the Energy Policy Act have only limited applicability to us, primarily in our capacity as a seller of natural gas, as the operator of interstate natural gas pipelines subject to limited jurisdiction certificates, and as operator of an intrastate natural gas pipeline offering interstate service under Section 311 of the NGPA. As such, we are subject to the Energy Policy Act as the owner of facilities, and thus we are subject to (1) civil penalties for violations of the Natural Gas Act; (2) the NGPA or FERC regulations or orders issued under those laws; and (3) for conduct determined to constitute market manipulation. The penalties associated with any violations of the Energy Policy Act could be substantial.

Other regulation of the natural gas and oil industry. The natural gas and oil industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in their industries with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the potential costs to comply with any such facility security laws or regulations, but such expenditures could be substantial.

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Properties

Our principal facilities consist of fourteen natural gas processing plants; eighteen gas treating facilities; approximately 11,200 miles of active 2 inch to 30 inch diameter natural gas gathering lines; and approximately 2,200 miles of NGL transportation pipeline through our 20% interest in WTLPG. Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

The following tables set forth certain information relating to our gas processing facilities, and natural gas gathering systems:

Gas Processing Facilities

Facility	Location	Year Constructed	Design Throughput Capacity (MMCFD)	2013 Average Utilization Rate
Atoka plant	Atoka County, OK	2006	20	
Coalgate plant	Coal County, OK	2007	80	
Tupelo plant	Coal County, OK	2011	120	
Velma plant	Stephens County, OK	Updated 2003	100	
Velma V-60 plant	Stephens County, OK	2012	60	
Total SouthOK			380	100%(1)
Silver Oak I	Bee County, TX	2012	200	
Total SouthTX			200	66%
Waynoka I plant	Woods County, OK	2006	200	
Waynoka II plant	Woods County, OK	2012	200	
Chaney Dell plant	Major County, OK	2012	30	
Chester plant	Woodward County, OK	1981	28	
Total WestOK			458	100%(1)
Consolidator plant	Reagan County, TX	2009	150	
Driver plant	Midland County, TX	2013	200	
Midkiff plant	Reagan County, TX	1990	60	
Benedum plant	Upton County, TX	Updated 1981	45	
Total WestTX			455	72%
Total			1,493	88%(1)

(1) Certain processing facilities in these business units are capable of processing more than their name-plate capacity and when capacity is exceeded we will off-load volumes to other processors, as needed. The calculation of the total average utilization rate for the year includes these off-loaded volumes.

Of the eighteen gas treating facilities we own, seventeen are used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas. Two of our contract gas treating facilities are refrigeration facilities and the other fifteen are amine facilities. The remaining treating facility is a 250 GPM amine treating plant which is used in our processing operations in the Arkoma system and is included in the Gathering and Processing segment. Our seventeen contract gas treating facilities are included in the Transportation and Treating segment.

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Natural Gas Gathering Systems

System	Location	Approximate Active Miles of Pipe
SouthOK	Southern Oklahoma and Northern Texas	1,300
SouthTX	Southern Central Texas	500
WestOK	North Central Oklahoma and Southern Kansas	5,700
WestTX	West Texas	3,600
Tennessee	Tennessee	70
Barnett Shale	Central Texas	20
Total		**11,190**

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not materially interfered, and we do not expect they will materially interfere, with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the rights-of-way grants. In a few instances, our rights-of-way are revocable at the election of the land owners. In some cases, not all of the owners named in the appropriate land records have joined in the rights-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary, although in some instances these permits are revocable at the election of the grantor. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor s election.

Certain of our rights to lay and maintain pipelines are derived from recorded gas well leases, with respect to wells currently in production; however, the leases are subject to termination if the wells cease to produce. Because many of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

Employees

As is commonly the case with publicly-traded limited partnerships, we do not directly employ any of the persons responsible for our management or operations. In general, employees of ATLS and its affiliates manage and operate our business. ATLS employed approximately 450 people at December 31, 2013 who provided direct support to our operations.

Affiliates of our General Partner will conduct business and activities of their own in which we will have no economic interest; and there could be material competition between us, our General Partner and affiliates of our General Partner for the time and effort of the officers and employees who provide services to our General Partner. Apart from our Executive Chairman and Executive Vice Chairman and officers providing services in the area of corporate development, the officers of our General Partner who provide services to us are generally assigned solely to our operations. However, they are not required to work full time on our affairs. These officers may also devote time to the affairs of our General Partner s affiliates and be compensated by these affiliates for the services rendered to them. There may be conflicts between us and affiliates of our General Partner regarding the availability of these officers to manage us.

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Available Information

We make our periodic reports under the Securities Exchange Act of 1934, including our annual report on Form 10-K, our quarterly reports on Form 10-Q and our current reports on Form 8-K, available through our website at www.atlaspipeline.com. To view these reports, click on Investor Relations, then SEC Filings. You may also receive, without charge, a paper copy of any such filings by request to us at Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011, telephone number (877) 950-7473. A complete list of our filings is available on the SEC s website at www.sec.gov. Any of our filings are also available at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

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ITEM 1A. RISK FACTORS

Partnership interests are inherently different from the 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 a similar business. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to Our Business

The amount of cash we generate depends, in part, on factors beyond our control.

The amount of cash we generate may not be sufficient for us to pay distributions at the current distribution levels or at all in the future. Our ability to make cash distributions depends primarily on our cash flows. Cash distributions do not depend directly on our profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when we record losses and may not be made during periods when we record profits. The actual amounts of cash we generate will depend upon numerous factors relating to our business, which may be beyond our control, including:

- the demand for natural gas, NGLs, crude oil and condensate;
- the price of natural gas, NGLs, crude oil and condensate (including the volatility of such prices);
- the amount of NGL content in the natural gas we process;
- the volume of natural gas we gather;
- efficiency of our gathering systems and processing plants;
- expiration of significant contracts;
- continued development of wells for connection to our gathering systems;
- our ability to connect new wells to our gathering systems;
- our ability to integrate newly-formed ventures or acquired businesses with our existing operations;
- the availability of local, intrastate and interstate transportation systems;

the availability of fractionation capacity;

the expenses we incur in providing our gathering services;

the cost of acquisitions and capital improvements;

required principal and interest payments on our debt;

fluctuations in working capital;

prevailing economic conditions;

fuel conservation measures;

alternate fuel requirements;

the strength and financial resources of our competitors;

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- the effectiveness of our commodity price risk management program and the creditworthiness of our derivatives counterparties;
- governmental (including environmental and tax) laws and regulations; and
- technical advances in fuel economy and energy generation devices.

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

- the level of capital expenditures we make;
- the sources of cash used to fund our acquisitions;
- limitations on our access to capital or the market for our common units and notes;
- our debt service requirements; and
- the amount of cash reserves established by our General Partner for the conduct of our business.

Our ability to make payments on and to refinance our indebtedness will depend on our financial and operating performance, which may fluctuate significantly from quarter to quarter, and is subject to prevailing economic and industry conditions and financial, business and other factors, many of which are beyond our control. We cannot assure you that we will continue to generate sufficient cash flow or that we will be able to borrow sufficient funds to service our indebtedness, or to meet our working capital and capital expenditure requirements. If we are not able to generate sufficient cash flow from operations or to borrow sufficient funds to service our indebtedness, we may be required to sell assets or equity, reduce capital expenditures, refinance all or a portion of our existing indebtedness or obtain additional financing. We cannot assure you that we will be able to refinance our indebtedness, sell assets or equity, or borrow more funds on terms acceptable to us, or at all.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by the financial markets and related effects in the global financial system. The consequences of an economic recession and the effects of a financial crisis may include a lower level of economic activity and/or increased volatility in energy prices. This may result in a decline in energy consumption and lower market prices for oil and natural gas, and has previously resulted in a reduction in drilling activity in our service area and in wells connected to our pipeline system being shut in by their operators until prices improved. Any of these events may adversely affect our revenues and our ability to fund capital expenditures and, in turn, may impact the cash we have available to fund our operations, pay required debt service and make distributions to our unitholders.

Instability in the financial markets may increase the cost of capital while reducing the availability of funds. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flow from operations and borrowings under our existing credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. Disruptions in the capital and credit markets could limit our access to liquidity needed for our business and impact our flexibility to react to changing economic and business conditions. Any disruption could require us to take measures to conserve cash until the markets stabilize or until we can arrange alternative credit arrangements or other funding for our business needs. Such measures could include reducing or delaying business activities, reducing our operations to lower expenses, and reducing other discretionary uses of cash. We may be unable to execute our growth strategy, take advantage of business opportunities or to respond to competitive pressures, any of which could negatively impact our business.

A weakening of the current economic situation could have an adverse impact on our lenders, producers, key suppliers or other customers, causing them to fail to meet their obligations to us. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow and ability to make required debt service payments and pay distributions could be impacted. The uncertainty and volatility surrounding the global financial crisis may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

We are affected by the volatility of prices for natural gas, NGL and crude oil products.

We derive a majority of our gross margin from POP and Keep-Whole contracts. As a result, our income depends to a significant extent upon the prices at which we buy and sell natural gas and at which we sell NGLs and condensate. Average estimated unhedged 2014 market prices for NGLs, natural gas and crude oil, based upon NYMEX forward price curves as of December 12, 2013, were $0.99 per gallon, $4.27 per MMBTU and $95.57 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended December 31, 2014 by approximately $15.5 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations, and could cause operators of wells currently connected to our pipeline system or that we expect will be connected to our system to shut in their production until prices improve, thereby affecting the volume of gas we gather and process. Historically, the prices of natural gas, NGLs and crude oil have been subject to significant volatility in response to relatively minor changes in the supply and demand for these products, market uncertainty and a variety of additional factors beyond our control, including those we describe in The amount of cash we generate depends, in part, on factors beyond our control, above. West Texas Intermediate crude oil prices traded in a range of $86.68 per barrel to $110.53 per barrel in 2013, while Henry Hub natural gas prices have traded in a range of $3.11 per MMBTU to $4.46 per MMBTU, during the same time period. We expect this volatility to continue. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our commodity price risk management strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all the throughput volumes. Moreover, derivative instruments are subject to inherent risks, which we describe in Our commodity price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

Our commodity price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

Our operations expose us to fluctuations in commodity prices. We utilize derivative contracts related to the future price of crude oil, natural gas and NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. To the extent we protect our commodity prices using derivative contracts we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. Our commodity price risk management activity may fail to protect or could harm us because, among other things:

- entering into derivative instruments can be expensive, particularly during periods of volatile prices;

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- available derivative instruments may not correspond directly with the risks against which we seek protection;

- price relationship between the physical transaction and the derivative transaction could change;

- the anticipated physical transaction could be different than projected due to changes in contracts, lower production volumes or other operational impacts, resulting in possible losses on the derivative instrument, which are not offset by income on the anticipated physical transaction; and

- the party owing money in the derivative transaction may default on its obligation to pay.

Regulations adopted by the Commodity Futures Trading Commission could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

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

The new regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities. As a commercial end-user, which uses swaps to hedge or mitigate commercial risk, rather than for speculative purposes, we are permitted to opt out of the clearing and exchange trading requirements. However, we could be exposed to greater liquidity and credit risk with respect to our hedging transactions if we do not use cleared and exchange-traded swaps. Counterparties to our derivative instruments, which are federally insured depository institutions, are required to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and/or cash flows.

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We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could negatively impact our business.

We have historically experienced minimal collection issues with our counterparties; however our revenue and receivables are highly concentrated in a few key customers and therefore we are subject to risks of loss resulting from nonpayment or nonperformance by our key customers. In an attempt to reduce this risk, we have established credit limits for each counterparty and we attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security. Nonetheless, we have key customers whose credit risk cannot realistically be otherwise mitigated. Furthermore, although we evaluate the creditworthiness of our counterparties, we may not always be able to fully anticipate or detect deterioration in their creditworthiness and overall financial condition, which could expose us to an increased risk of nonpayment or other default under our contracts and other arrangements with them. Any material nonpayment or nonperformance by our key customers could impact our cash flow and ability to make required debt service payments and pay distributions.

Due to our lack of asset diversification, negative developments in our operations could reduce our ability to fund our operations, pay required debt service and make distributions to our common unitholders.

We rely primarily on the revenues generated from our gathering, processing and treating operations, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, NGLs and condensate. Due to our lack of asset-type diversification, a negative development in this business could have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

The amount of natural gas we gather will decline over time unless we are able to attract new wells to connect to our gathering systems.

Production of natural gas from a well generally declines over time until the well can no longer economically produce natural gas and is plugged and abandoned. Failure to connect new wells to our gathering systems could, therefore, result in the amount of natural gas we gather declining substantially over time and could, upon exhaustion of the current wells, cause us to abandon one or more of our gathering systems and, possibly, cease operations. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing wells not committed to other systems, the level of drilling activity near our gathering systems and our ability to attract natural gas producers away from our competitors gathering systems.

Over time, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. A decrease in exploration and development activities in the fields served by our gathering, processing and treating facilities could result if there is a sustained decline in natural gas, crude oil and/or NGL prices, which, in turn, would lead to a reduced utilization of these assets. The decline in the credit markets, the lack of availability of credit, debt or equity financing and the decline in commodity prices may result in a reduction of producers exploratory drilling. We have no control over the level of drilling activity in our service areas, the amount of reserves underlying wells that connect to our systems and the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, drilling costs, geological considerations, governmental regulation and the availability and cost of capital. In a low price environment, producers may determine to shut in wells already connected to our systems until prices improve. Because our operating costs are fixed to a significant degree, a reduction in the natural gas volumes we gather or process would result in a reduction in our gross margin and cash flow.

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Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in reduced volumes available for us to gather and process.

Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a process that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. The adoption of any future federal, state or local laws or regulations imposing additional permitting, disclosure or regulatory obligations related to, or otherwise restricting or increasing costs regarding the use of, hydraulic fracturing could make it more difficult to drill certain oil and natural gas wells. As a result, the volume of natural gas we gather and process from producer wells in our service area that use hydraulic fracturing could be substantially reduced, which could adversely affect our gross margin and cash flow.

We currently depend on certain key producers for their supply of natural gas; the loss of any of these key producers could reduce our revenues.

During 2013, Atoka Midstream, LLC; Chesapeake Energy Corporation; COG Operating LLC; Endeavor Energy Resources LP; Energen Resources Corporation; Laredo Petroleum Inc.; Parsley Energy, LP; Pioneer; SandRidge Exploration and Production, LLC; Vanguard Permian, LLC; Woolsey Operating Company LLC; and XTO accounted for a significant amount of our natural gas supply. If these producers reduce the volumes of natural gas they supply to us, our gross margin and cash flow could be reduced unless we obtain comparable supplies of natural gas from other producers.

We may face increased competition in the future.

We face competition for well connections.

Carrera Gas Company; DCP Midstream, LLC; Devon Energy Corporation; Enable Midstream Partners, L.P.; Energy Transfer Partners, L.P.; Kinder Morgan Energy Partners, L.P.; and ONEOK Field Services Company, operate competing gathering systems and processing plants in our SouthOK service areas.

DCP Midstream Partners, LLC; Energy Transfer Partners, L.P.; Enterprise Products Partners, L.P.; Howard Energy Partners, LLC; Kinder Morgan Energy Partners, L.P.; Regency Energy Partners, L.P.; Southcross Energy Partners, L.P.; and TexStar Midstream Services, L.P. operate competing gathering systems and processing plants in our SouthTX service area.

Access Midstream Partners, L.P.; Caballo Energy, LLC.; Duke Energy Corporation; Lumen Midstream Partners, LLC; Mustang Fuel Corporation; ONEOK Field Services Company; SemGas, L.P.; and Superior Pipeline Company, LLC operate competing gathering systems and processing plants in our WestOK service area.

Crosstex Energy Services; DCP Midstream, LLC; Energy Transfer Partners, L.P.; Regency Energy Partners, L.P., Targa Resources Partners; and West Texas Gas, Inc. operate competing gathering systems and processing plants in our WestTX service area.

Some of our competitors have greater financial and other resources than we do. If these companies become more active in our service areas, we may not be able to compete successfully with them in securing new well connections or retaining current well connections. In addition, customers who are significant producers of natural gas may develop their own gathering and processing systems in lieu of using those operated by us. If we do not compete successfully, the amount of natural gas we gather and process will decrease, reducing our gross margin and cash flow.

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The amount of natural gas we gather or process may be reduced if the intrastate and interstate pipelines to which we deliver natural gas or NGLs cannot or will not accept the gas.

Our gathering systems principally serve as intermediate transportation facilities between wells connected to our systems and the intrastate or interstate pipelines to which we deliver natural gas. Our plant tailgate pipelines, including the Driver Residue Pipeline and the APL SouthTex Transmission Section 311 pipeline, provide essential links between our processing plants and intrastate and interstate pipelines that move natural gas to market. We deliver NGLs to intrastate or interstate pipelines at the tailgates of the plants. If one or more of the pipelines or fractionation facilities to which we deliver natural gas and NGLs has service interruptions, capacity limitations or otherwise cannot or do not accept natural gas or NGLs from us, and we cannot arrange for delivery to other pipelines or fractionation facilities, the amount of natural gas we gather and process may be reduced. Since our revenues depend upon the volumes of natural gas we gather and natural gas and NGLs we sell or transport, this could result in a material reduction in our gross margin and cash flow.

Failure of the natural gas or NGLs we deliver to meet the specifications of interconnecting pipelines could result in curtailments by the pipelines.

The pipelines to which we deliver natural gas and NGLs typically establish specifications for the products they are willing to accept. These specifications include requirements such as hydrocarbon dew point, compositions, temperature, and foreign content (such as water, sulfur, carbon dioxide, and hydrogen sulfide), and these specifications can vary by product or pipeline. If the total mix of a product that we deliver to a pipeline fails to meet the applicable product quality specifications, the pipeline may refuse to accept all or a part of the products scheduled for delivery to it or may invoice us for the costs to handle the out-of-specification products. In those circumstances, we may be required to find alternative markets for that product or to shut-in the producers of the non-conforming natural gas causing the products to be out of specification, potentially reducing our through-put volumes or revenues.

The success of our operations depends upon our ability to continually find and contract for new sources of natural gas supply.

Our agreements with most producers with which we do business generally do not require them to dedicate significant amounts of undeveloped acreage to our systems. While we do have some undeveloped acreage dedicated on our systems, most notably with our partner Pioneer on our WestTX system, we do not have assured sources to provide us with new wells to connect to our gathering systems. Failure to connect new wells to our operations, as described in The amount of natural gas we gather will decline over time unless we are able to attract new wells to connect to our gathering systems, above, could reduce our gross margin and cash flow.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, our cash flow could be reduced.

We do not own all the land on which our pipelines are constructed. We obtain the rights to construct and operate our pipelines on land owned by third parties. In some cases, these rights expire at a specified time. Therefore we are subject to the possibility of more onerous terms 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. 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 and financial condition. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flow could be reduced.

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A change in the regulations related to a state s use of eminent domain could inhibit our ability to secure rights-of way for future pipeline construction projects.

Certain states where we operate are considering the adoption of laws and regulations that would limit or eliminate a state s ability to exercise eminent domain over private property. This, in turn, could make it more difficult or costly for us to secure rights-of-way for future pipeline construction and other projects. Further, states may amend their procedures for certain entities within the state to use eminent domain.

The scope and costs of the risks involved in making acquisitions may prove greater than estimated at the time of the acquisition.

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

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- mistaken assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- delays in obtaining any required regulatory approvals or third party consents;
- the imposition of conditions on any acquisition by a regulatory authority;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel;
- customer or key employee losses at the acquired businesses; and

- the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to make or increase distributions.

We may be unsuccessful in integrating the operations from prior or any future acquisitions with our operations and in realizing all the anticipated benefits of these acquisitions.

We continue to have an active, on-going program to identify potential acquisitions. Our integration of previously independent operations, with our own can be a complex, costly and time-consuming process. The difficulties of combining these systems with existing systems include, among other things:

- operating a significantly larger combined entity;
- the necessity of coordinating geographically disparate organizations, systems and facilities;
- integrating personnel with diverse business backgrounds and organizational cultures;
- consolidating operational and administrative functions;
- integrating pipeline safety-related records and procedures;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management s attention from other business concerns;
- customer or key employee loss from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Our investment and the additional overhead costs we incur to grow our business may not deliver the expected incremental volume or cash flow. Costs incurred and liabilities assumed in connection with the acquisition and increased capital expenditures and overhead costs incurred to expand our operations could harm our business or future prospects, and result in significant decreases in our gross margin and cash flow.

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

We are actively growing our business through the construction of new assets. The construction of additions or modifications to our existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. If endangered species are located in areas where we propose to construct new gathering or processing facilities, such work could be prohibited or delayed or expensive mitigation may be required. Any projects we undertake may not be completed on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a gathering system, the construction may occur over an extended period of time, and we will not receive any material increase in revenues until the project is completed. Moreover, we are constructing facilities to capture anticipated future growth in production in a region in which growth may not materialize. Since we are not engaged in the exploration for, and development of, natural gas reserves, we often do not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, the estimates may

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prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could impair our results of operations and financial condition. In addition, our actual revenues from a project could materially differ from expectations as a result of the volatility in the price of natural gas, the NGL content of the natural gas processed and other economic factors described in this section.

We continue to expand the natural gas gathering systems surrounding our facilities in order to maximize plant throughput. In addition to the risks discussed above, expected incremental revenue from recent projects could be reduced or delayed due to the following reasons:

- difficulties in obtaining capital for additional construction and operating costs;
- difficulties in obtaining permits or other regulatory or third-party consents;
- additional construction and operating costs exceeding budget estimates;
- revenue being less than expected due to lower commodity prices or lower demand;
- difficulties in obtaining consistent supplies of natural gas; and
- terms in operating agreements that are not favorable to us.

We may not be able to execute our growth strategy successfully.

Our strategy contemplates substantial growth through both the acquisition of other gathering systems and processing assets and the expansion of our existing gathering systems and processing assets. Our growth strategy through acquisitions involves numerous risks, including:

- we may not be able to identify suitable acquisition candidates;
- we may not be able to make acquisitions on economically acceptable terms for various reasons, including limitations on access to capital and increased competition for a limited pool of suitable assets;
- our costs in seeking to make acquisitions may be material, even if we cannot complete any acquisition we have pursued;

irrespective of estimates at the time we make an acquisition, the acquisition may prove to be dilutive to earnings and operating surplus;

we may encounter delays in receiving regulatory approvals or may receive approvals that are subject to material conditions;

we may encounter difficulties in integrating operations and systems; and

any additional debt we incur to finance an acquisition may impair our ability to service our existing debt.

Limitations on our access to capital or the market for our common units could impair our ability to execute our growth strategy.

Our ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, we have financed our acquisitions and expansions through bank credit facilities and the proceeds of public and private debt and equity offerings. If we are unable to access the capital markets, we may be unable to execute our growth strategy.

Our debt levels and restrictions in our revolving credit facility and the indentures governing our senior notes could limit our ability to fund operations and pay required debt service.

We have a significant amount of debt. We will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, which will reduce the funds that would otherwise be available for operations and future business opportunities. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures; selling assets; restructuring or refinancing our indebtedness; or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms, or at all.

Our revolving credit facility and the indentures governing our senior notes contain covenants limiting the ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to unitholders. Our revolving credit facility also contains covenants requiring us to maintain certain financial ratios and may limit our ability to capitalize on acquisitions and other business opportunities.

Increases in interest rates could adversely affect our unit price.

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

An impairment of goodwill, long-lived assets, including intangible assets, and equity-method investments could reduce our earnings.

In connection with our acquisitions in fiscal years 2007, 2012 and 2013, we have recorded goodwill and identifiable intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. We recorded an impairment charge of $43.9 million, during the year ended December 31, 2013, with respect to certain assets we acquired from Cardinal Midstream, LLC in December 2012 (the Cardinal Acquisition). Although we have not experienced any other events or circumstances that indicate that the carrying amounts of our other intangible assets and goodwill were impaired, we could experience future events that result in impairments. An impairment of the value of our existing goodwill and intangible assets could have a significant negative impact on our future operating results and could have an adverse impact on our ability to satisfy the financial ratios or other covenants under our existing or future debt agreements.

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Regulation of our gathering operations could increase our operating costs; decrease our revenue; or both.

Our gathering and processing of natural gas is exempt from regulation by FERC, under the Natural Gas Act of 1938. While gas transmission activities conducted through our plant tailgate pipelines, such as the Driver Residue Pipeline and the SouthTX Residue Pipeline, are subject to FERC s Natural Gas Act jurisdiction, FERC may limit the extent to which it regulates those activities. The way we operate, the implementation of new laws or policies (including changed interpretations of existing laws) or a change in facts relating to our plant tailgate pipeline operations could subject our operations to more extensive regulation by FERC under the Natural Gas Act, the Natural Gas Policy Act, or other laws. Any such regulation could increase our costs; decrease our gross margin and cash flow, or both.

Even if our gathering and processing of natural gas is not generally subject to regulation under the Natural Gas Act, FERC regulation will still affect our business and the market for our products. FERC s policies and practices affect a range of natural gas pipeline activities, including, for example, its policies on interstate natural gas pipeline open access transportation, ratemaking, capacity release, environmental protection and market center promotion, which indirectly affect intrastate markets. FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. We cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Since federal law generally leaves any economic regulation of natural gas gathering to the states, state and local regulations may also affect our business. Matters subject to such regulation include access, rates, terms of service and safety. For example, our gathering lines are subject to ratable take, common purchaser, and similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without discrimination, natural gas production that may be tendered to the gatherer for handling. Kansas, Oklahoma and Texas have adopted 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 natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed with the Texas Railroad Commission, Oklahoma Corporation Commission or Kansas Corporation Commission, or should one or more of these agencies become more active in regulating our industry, our revenues could decrease. Collectively, all of these statutes may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Compliance with pipeline integrity regulations issued by the DOT and state agencies could result in substantial expenditures for testing, repairs and replacement.

DOT and state agency regulations require pipeline operators to develop integrity management programs for transportation pipelines located in high consequence areas. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;

- repair and remediate the pipeline as necessary; and

- implement preventative and mitigating actions.

While we do not believe that the cost of implementing integrity management program testing along segments of our pipeline will have a material effect on our results of operations, the costs of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program could be substantial.

Our midstream natural gas operations could incur significant costs if PHMSA adopts more stringent regulations governing our business.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the Act, was signed into law. The Act directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in natural gas and hazardous liquids pipeline safety rulemakings. These rulemakings will be conducted by PHMSA.

Since passage of the Act, PHMSA has published several notices of proposed rulemaking which propose a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities, including increased safety requirements and increased penalties.

The adoption of regulations that apply more comprehensive or stringent safety standards to gathering lines could require us to install new or modified safety controls, incur additional capital expenditures, or conduct maintenance programs on an accelerated basis. Such requirements could result in our incurrence of increased operational costs that could be significant; or if we fail to, or are unable to, comply, we may be subject to administrative, civil and criminal enforcement actions, including assessment of monetary penalties or suspension of operations, which could have a material adverse effect on our financial position or results of operations and our ability to make distributions to our unitholders.

Our midstream natural gas operations may incur significant costs and liabilities resulting from a failure to comply with new or existing environmental regulations or a release of regulated materials into the environment by us or the producers in our service areas.

The operations of our gathering systems, plants and other facilities, as well as the operations of the producers in our service areas, are subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we, and our producers, dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. 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, increased cost of operations, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances and 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 regulated substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of regulated substances into the environment, and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from (1) environmental cleanup, restoration costs and

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natural resource damages; (2) claims made by neighboring landowners and other third parties for personal injury and property damage; and (3) fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies, including those relating to emissions from production, processing and transmission activities, could significantly increase our compliance costs and the cost of any remediation that may become necessary. Producers in our service areas may curtail or abandon exploration and production activities if any of these regulations cause their operations to become uneconomical. We may not be able to recover some or any of these costs from insurance.

Climate change legislation or regulations at the international, federal and state levels restricting emissions of greenhouse gases (GHGs) could result in increased operating costs and reduced demand for our midstream services.

In response to findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climate changes, the EPA adopted regulations under existing provisions of the federal Clean Air Act that require entities that produce certain gases to inventory, monitor and report such gases. Additionally, the EPA adopted rules to regulate GHG emissions through traditional major source construction and operating permit programs. The EPA confirmed the permitting thresholds established in a 2010 rule in July 2012. These permitting programs require consideration of and, if deemed necessary, implementation of best available control technology to reduce GHG emissions. In addition there are several international and state level initiatives and proposals addressing domestic and global climate issues. As a result, our operations could face additional costs for emissions control and higher costs of doing business.

Litigation or governmental regulation relating to environmental protection and operational safety may result in substantial costs and liabilities.

Our operations are subject to federal and state environmental laws under which owners of natural gas pipelines can be liable for clean-up costs and fines in connection with any pollution caused by their pipelines. We may also be held liable for clean-up costs resulting from pollution that occurred before our acquisition of a gathering system. In addition, we are subject to federal and state safety laws that dictate the type of pipeline, quality of pipe protection, depth of pipelines, methods of welding and other construction-related standards, as well as certain operations and maintenance practices. Any violation of environmental, construction or safety laws could impose substantial liabilities and costs on us.

We are also subject to the requirements of OSHA, and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

Oil and gas operators can be impacted by litigation brought against the agencies which regulate the oil and gas industry. The outcomes of such activities can impact our operations.

We cannot predict whether or in what form any new litigation or regulatory requirements might be enacted or adopted, nor can we predict our costs of compliance. In general, we expect new regulations would increase our operating costs and, possibly, require us to obtain additional capital to pay for improvements or other compliance actions necessitated by those regulations.

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We are subject to operating and litigation risks that may not be covered by insurance.

Our operations are subject to all operating hazards and risks incidental to gathering, processing and treating natural gas and NGLs. These hazards include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods and other natural disasters;
- inadvertent damage from construction and farm equipment;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions;
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations;
- nuisance and other landowner claims arising from our operations; and
- acts of terrorism directed at our pipeline infrastructure, production facilities and surrounding properties.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. 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 some of our insurance policies have increased substantially in recent years, and could escalate further. Our existing insurance coverage does not cover all potential losses, costs, or liabilities and we could suffer losses in amounts in excess of our existing insurance coverage. Moreover, in some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers require broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability, for which we were not fully insured, our gross margin and cash flow would be materially reduced.

The loss of key personnel could adversely affect our ability to operate.

Our ability to manage and grow our business effectively may be adversely affected if we lose key management or operational personnel. We depend on the continuing efforts of our General Partner s executive officers. The departure of any of these executive officers could have a significant negative impact on our business, operating results, financial condition, and on our ability to compete effectively in the marketplace. Additionally, our ability to hire, train, and retain qualified personnel will continue to be important and will become more challenging as we grow. Our ability to grow and to continue our current level of service to our customers will be adversely impacted if we are unable to successfully hire, train and retain these important personnel.

Catastrophic weather events may curtail operations at, or cause closure of, any of our processing plants, which could harm our business.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. If operations at any of our processing plants were to be curtailed, or closed, whether due to natural catastrophe, accident, environmental regulation, periodic maintenance, or for any other reason, our ability to process natural gas from the relevant gathering system and, as a result, our ability to extract and sell NGLs, would be harmed. If this curtailment or stoppage were to extend for more than a short period, our gross margin and cash flow could be materially reduced.

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Disruption due to political uncertainties, civil unrest or the threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact our results of operations and our ability to raise capital.

Political uncertainties, civil unrest and terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Such disruptions could adversely affect our operations and the markets for our products and services, including through increased volatility in crude oil and natural gas prices, or the possibility that our infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. In addition, instabilities in the financial and insurance markets caused by such disruptions may make it more difficult for us to access capital and may increase insurance premiums or make it difficult to obtain the insurance coverage that we consider adequate.

Risks Relating to Our Ownership Structure

ATLS and its affiliates have conflicts of interest and limited fiduciary responsibilities, which may permit it to favor its own interests to the detriment of our unitholders.

ATLS owns and controls our General Partner and also has a 6.0% limited partner interest in us. We do not have any employees and rely solely on employees of ATLS and its affiliates, who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of ATLS also own interests in us. Conflicts of interest may arise between ATLS, our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over our interests and the interests of our unitholders. These conflicts include, among others, the following situations:

Employees of ATLS who provide services to us also devote time to the businesses of ATLS in which we have no economic interest. If these separate activities are greater than our activities, there could be material competition for the time and effort of the employees who provide services to our General Partner, which could result in insufficient attention to the management and operation of our business.

Neither our partnership agreement nor any other agreement requires ATLS to pursue a future business strategy that favors us or to use our gathering or processing services. ATLS directors and officers have a fiduciary duty to make these decisions in the best interests of the unitholders of ATLS.

Our General Partner is allowed to take into account the interests of parties other than us, such as ATLS, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us.

Our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates. Conflicts of interest with ATLS and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our gross margin and cash flow.

Cost reimbursements due to our General Partner may be substantial.

We reimburse ATLS, our General Partner and its affiliates, including officers and directors of ATLS, for all expenses they incur on our behalf. Our General Partner has sole discretion to determine the amount of these expenses. In addition, ATLS provides us with services for which we are charged reasonable fees as determined by ATLS in its sole discretion. The reimbursement of expenses or payment of fees could adversely affect our ability to fund our operations and pay required debt service.

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 not elect our General Partner or the managing board of our General Partner and have no right to elect our General Partner or the managing board of our General Partner on an annual or other continuing basis. The managing board of our General Partner is chosen by ATLS, the owner of 100% of the equity of our General Partner. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

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 the owners of our General Partner from transferring all or a portion of their respective ownership interest in our General Partner to a third party. The new owners of our General Partner would then be in a position to replace the managing board and officers of our General Partner with its own choices and thereby influence the decisions taken by the managing board and officers.

We may issue additional units without unitholder approval, which would dilute 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, including units that rank senior to our common units as to quarterly cash distributions. 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; and
- the market price of the common units may decline.

We own and operate certain of our systems through joint ventures, and our control of such systems is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint venture entities.

Certain of our joint ventures are structured so that a subsidiary of ours is the managing member of the limited liability company that owns the system being operated. However, the operational agreements applicable to such joint venture entities generally require consent of our joint venture partner for specified extraordinary transactions, such as admission of new members; engaging in transactions with our affiliates not approved by the company conflicts committee; incurring debt outside the ordinary course of business; and disposing of company assets above specified thresholds.

In addition, certain of our systems are operated by joint venture entities that we do not operate, or in which we do not have an ownership stake that permits us to control the business activities of the entity. We have limited ability to influence the business decisions of such joint venture entities, and we may be unable to control the amount of cash we will receive from the operation and could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Tax Risks Relating to Unit Ownership

If we were treated as a corporation for federal income tax purposes, or if we were to become subject to a material amount of entity-level taxation for federal or state income tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.

We are currently treated as a partnership for federal income tax purposes, which requires that 90% or more of our gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code. Qualifying income is defined as income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber). We may not meet this requirement or current law may change so as to cause, in either event, us to be treated as a corporation for federal income tax purposes or otherwise subject to federal income tax. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

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. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in our anticipated cash flows, likely causing a substantial reduction in the value of our units.

Current tax law may change, causing us to be treated as a corporation for federal and/or state income tax purposes or otherwise subjecting us to entity level taxation. For example, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced. Furthermore, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income, adversely affect an investment in our common units or otherwise negatively impact the value of an investment in our common units.

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Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability, which results from the taxation of their share of our taxable income.

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

If a unitholder sells their common units, they will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions and the allocation of losses, including depreciation deductions, to the unitholder in excess of the total net taxable income allocated to them, which decreased the tax basis in their common units, will, in effect, become taxable income to them if the common units are sold at a price greater than their tax basis in those common units, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder.

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

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

We treat each purchaser of our common units as having the same tax benefits without regard to the 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, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders tax returns.

The sale or exchange of 50% or more of our capital and profits interest within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interest in our capital and profits within a 12-month period. The termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year in which the termination occurs. Thus, if this occurs, the unitholder will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to the unitholder with respect to that period.

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Unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We presently anticipate substantially all of our income will be generated in Oklahoma, and Texas. Oklahoma currently imposes a personal income tax. We may do business or own property in other states in the future. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

The IRS may challenge our tax treatment related to transfers of units, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction 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. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our positions. A court may not agree with some or all of our positions. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which they trade. In addition, we will bear the costs of any contest with the IRS thereby reducing the cash available for distribution to our unitholders.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public unitholders. The IRS may challenge this treatment, which could adversely affect the value of our 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 such assets to the capital accounts of our unitholders and our General Partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our General Partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of our common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our General Partner and certain of our unitholders.

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

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

Because a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

ITEM 1B: UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2: PROPERTIES

A description of our properties is contained within Item 1, Business Properties.

ITEM 3: LEGAL PROCEEDINGS

Not applicable.

ITEM 4: MINE SAFETY DISCLOSURE

Not applicable.

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PART II

ITEM 5: MARKET FOR REGISTRANT S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the New York Stock Exchange under the symbol APL. At the close of business on February 17, 2014, the closing price for the common units was $33.08 and there were 103 record holders, one of which is the holder for all beneficial owners who hold in street name.

The following table sets forth the range of high and low sales prices of our common units and distributions declared by quarter per unit on our common limited partner units for the years ended December 31, 2013 and 2012:

	High	Low	Distributions Declared
2013			
Fourth Quarter	$ 40.02	$ 32.50	$ 0.62
Third Quarter	40.06	35.07	0.62
Second Quarter	39.94	33.05	0.62
First Quarter	34.82	31.55	0.59
2012			
Fourth Quarter	$ 36.10	$ 29.53	$ 0.58
Third Quarter	36.09	30.55	0.57
Second Quarter	36.04	27.32	0.56
First Quarter	40.89	34.78	0.56

Our Cash Distribution Policy

Our partnership agreement requires we distribute 100% of available cash, for each calendar quarter, to our General Partner and common limited partners within 45 days following the end of such calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our General Partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common unitholders exceed specified targets, as follows:

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Minimum Distributions Per Unit Per Quarter	Percent of Available Cash in Excess of Minimum Allocated to General Partner[(1)]
$0.42	15%
0.52	25%
0.60	50%

(1) Percent allocated to our General Partner includes 2% general partner interest in addition to incentive distributions.

We make distributions of available cash to common unitholders regardless of whether the amount distributed is less than the minimum quarterly distribution. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. Our General Partner, the holder of all our incentive distribution rights, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial $7.0 million per quarter of incentive distribution rights. The General Partner s incentive distributions paid for the years ended December 31, 2013 and 2012 were $15.0 million and $6.3 million, respectively.

For information concerning units authorized for issuance under our long-term incentive plans, see Item 12: Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

ITEM 6: SELECTED FINANCIAL DATA

The following table should be read together with our consolidated financial statements and notes thereto included within Item 8: Financial Statements and Supplementary Data and Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations of this report. We have derived the selected financial data set forth in the table for each of the years ended December 31, 2013, 2012 and 2011 and at December 31, 2013 and 2012 from our consolidated financial statements appearing elsewhere in this report, which have been audited by Grant Thornton LLP, independent registered public accounting firm. We derived the financial data for the years ended December 31, 2010 and 2009 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

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	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Statements of operations data:					
Revenue:					
Natural gas and liquids sales	$ 1,959,144	$ 1,137,261	$ 1,268,195	$ 890,048	$ 636,231
Transportation, processing and other fees	165,177	66,722	43,799	41,093	59,075
Derivative gain (loss)	(28,764)	31,940	(20,452)	(5,945)	(35,815)
Other income, net	11,292	10,097	11,192	10,392	13,114
Total revenues	2,106,849	1,246,020	1,302,734	935,588	672,605
Costs and expenses:					
Natural gas and liquids cost of sales	1,690,382	927,946	1,047,025	720,215	527,730
Plant operating	92,271	60,480	54,686	48,670	45,566
Transportation and compression	2,256	1,618	833	1,061	6,657
General and administrative(1)	60,856	47,206	36,357	34,021	37,280
Other costs	20,005	15,069	1,040		
Depreciation and amortization	168,617	90,029	77,435	74,897	75,684
Interest	89,637	41,760	31,603	87,273	101,309
Total costs and expenses	2,124,024	1,184,108	1,248,979	966,137	794,226
Equity income (loss) in joint ventures	(4,736)	6,323	5,025	4,920	4,043
Gain (loss) on asset sales and other(2)	(1,519)		256,272	(10,729)	108,947
Goodwill and other asset impairment loss	(43,866)				(10,325)
Loss on early extinguishment of debt	(26,601)		(19,574)	(4,359)	(2,478)
Income (loss) from continuing operations before tax	(93,897)	68,235	295,478	(40,717)	(21,434)
Income tax expense (benefit)	(2,260)	176			
Income (loss) from continuing operations	(91,637)	68,059	295,478	(40,717)	(21,434)
Income (loss) from discontinued operations net of tax			(81)	321,155	84,148
Net income (loss)	(91,637)	68,059	295,397	280,438	62,714
Income attributable to non-controlling interests(3)	(6,975)	(6,010)	(6,200)	(4,738)	(3,176)
Preferred unit imputed dividend effect	(29,485)				
Preferred unit dividends in kind	(23,583)				
Preferred unit dividends			(389)	(780)	(900)
Net income (loss) attributable to common limited partners and the General Partner	$ (151,680)	$ 62,049	$ 288,808	$ 274,920	$ 58,638

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	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands, except per unit data)				
Allocation of net income (loss) attributable to:					
Common limited partner interest:					
Continuing operations	$ (165,923)	$ 52,391	$ 281,449	$ (45,347)	$ (24,997)
Discontinued operations			(79)	315,021	82,457
	(165,923)	52,391	281,370	269,674	57,460
General Partner interest:					
Continuing operations	14,243	9,658	7,440	(888)	(513)
Discontinued operations			(2)	6,134	1,691
	14,243	9,658	7,438	5,246	1,178
Net income (loss) attributable to:					
Continuing operations	(151,680)	62,049	288,889	(46,235)	(25,510)
Discontinued operations			(81)	321,155	84,148
	$ (151,680)	$ 62,049	$ 288,808	$ 274,920	$ 58,638
Net income (loss) attributable to common limited partners per unit:					
Basic:					
Continuing operations	$ (2.23)	$ 0.95	$ 5.22	$ (0.85)	$ (0.52)
Discontinued operations				5.92	1.71
	$ (2.23)	$ 0.95	$ 5.22	$ 5.07	$ 1.19
Diluted[4]:					
Continuing operations	$ (2.23)	$ 0.95	$ 5.22	$ (0.85)	$ (0.52)
Discontinued operations				5.92	1.71
	$ (2.23)	$ 0.95	$ 5.22	$ 5.07	$ 1.19

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	Years Ended December 31,				
	2013	2012	2011	2010	2009
			(in thousands)		
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 2,724,192	$ 2,200,381	$ 1,567,828	$ 1,341,002	$ 1,327,704
Total assets	4,327,845	3,065,638	1,930,812	1,764,848	2,137,963
Total debt, including current portion	1,707,310	1,179,918	524,140	565,974	1,254,183
Total equity	2,259,905	1,606,408	1,236,228	1,041,647	723,527
Cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 210,844	$ 174,638	$ 102,867	$ 106,427	$ 55,853
Investing activities	(1,443,083)	(1,006,641)	67,763	594,753	241,123
Financing activities	1,233,755	835,233	(170,626)	(702,037)	(297,400)
Other financial data (unaudited):					
Gross margin from continuing operations (5)	$ 434,188	$ 278,148	$ 264,923	$ 210,580	$ 163,677
EBITDA (6)	164,357	200,024	404,435	443,212	240,150
Adjusted EBITDA (6)	324,870	220,207	181,026	209,799	174,808
Maintenance capital expenditures	$ 21,919	$ 19,021	$ 18,247	$ 10,921	$ 3,750
Expansion capital expenditures (7)	428,641	354,512	227,179	35,715	106,524
Total capital expenditures	$ 450,560	$ 373,533	$ 245,426	$ 46,636	$ 110,274

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	Years Ended December 31,				
	2013	2012	2011	2010	2009
Operating data (unaudited):					
SouthOK system:					
Velma:					
Gathered gas volume (MCFD)	147,300	128,548	103,328	84,455	76,378
Processed gas volume (MCFD)	140,571	114,421	98,126	78,606	73,940
Residue gas volume (MCFD)	117,079	100,711	80,330	64,138	58,350
NGL volume (BPD)	16,067	13,850	11,433	9,218	8,232
Condensate volume (BPD)	379	409	423	416	377
Arkoma(8):					
Gathered gas volume (MCFD)	258,773	222,045			
Processed gas volume (MCFD)	238,161	211,032			
Residue gas volume (MCFD)	206,946	174,604			
NGL volume (BPD)	19,021	16,138			
Condensate volume (BPD)	146	122			
SouthTX system:					
Gathered gas volume (MCFD)	132,826				
Processed gas volume (MCFD)	131,745				
Residue gas volume (MCFD)	105,207				
NGL volume (BPD)	16,711				
Condensate volume (BPD)	77				
WestOK system:					
Gathered gas volume (MCFD)	500,756	369,035	268,329	228,684	270,703
Processed gas volume (MCFD)	475,441	348,041	254,394	214,695	215,374
Residue gas volume (MCFD)	438,611	322,751	230,907	193,200	228,261
NGL volume (BPD)	20,971	14,505	13,635	12,395	13,418
Condensate volume (BPD)	1,887	1,360	898	697	824
WestTX system(8):					
Gathered gas volume (MCFD)	357,524	275,946	212,775	178,111	159,568
Processed gas volume (MCFD)	328,678	249,221	196,412	163,475	149,656
Residue gas volume (MCFD)	244,294	179,539	133,857	105,982	101,788
NGL volume (BPD)	41,920	32,314	29,052	26,678	21,261
Condensate volume (BPD)	1,657	1,524	1,500	1,289	1,265
Barnett system:					
Average throughput volume (MCFD)	21,356	22,935			
Tennessee system:					
Average throughput volume (MCFD)	8,300	8,487	7,698	8,740	7,907
WTLPG system(8):					
Average throughput volume (BPD)	245,599	249,533	229,673		

(1) Includes non-cash compensation (income) expense of $19.3 million, $11.6 million, $3.3 million, $3.5 million and $0.7 million for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively; and includes compensation reimbursement to affiliates.

(2) Represents the gain on sale of assets to Laurel Mountain in 2009 and the gain on sale of our 49% non-controlling interest in Laurel Mountain in 2011 (see Item 8. Financial Statements and Supplementary Data Note 4).

(3)

Represents Anadarko Petroleum Corporation s (Anadarko NYSE: APC) non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest Oklahoma Gas Company, LLC s (MarkWest) non-controlling interest in Centrahoma.

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(4) For the years ended December 31, 2013, 2010 and 2009, approximately 1,240,000, 300,000 and 82,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such phantom units would have been anti-dilutive. For the year ended December 31, 2013, approximately 9,110,000 Class D Preferred Units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such preferred units would have been anti-dilutive. For the years ended December 31, 2010 and 2009, 75,000 and 100,000 unit options, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such unit options would have been anti-dilutive. For the year ended December 31, 2009, potential common limited partner units issuable upon exercise of our warrants were excluded from computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

(5) We define gross margin from continuing operations as natural gas and liquids sales and transportation, processing and other fees less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas and NGLs we purchase from third parties. Gross margin, as we define it, does not include plant operating expenses; transportation and compression expenses; and derivative gain (loss) related to ineffective or undesignated hedges, as movements in gross margin generally do not result in directly correlated movements in these categories. Plant operating and transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, real estate taxes and other overhead costs. Our management views gross margin as an important performance measure of core profitability for our operations and as a key component of our internal financial reporting. We believe investors benefit from having access to the same financial measures that our management uses. The following table reconciles net income (loss) to gross margin from continuing operations (in thousands):

RECONCILIATION OF GROSS MARGIN FROM CONTINUING OPERATIONS

	Years Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
			(in thousands)		
Net income (loss)	$ (91,637)	$ 68,059	$ 295,397	$ 280,438	$ 62,714
Derivative (gain) loss, net	28,764	(31,940)	20,452	5,340	35,372
Other income, net	(11,292)	(10,097)	(11,192)	(9,787)	(12,671)
Operating expenses(9)	114,532	77,167	56,559	49,731	52,223
General and administrative expense(1)	60,856	47,206	36,357	34,021	37,280
Depreciation and amortization	168,617	90,029	77,435	74,897	75,684
Interest	89,637	41,760	31,603	87,273	101,309
Income tax expense (benefit)	(2,260)	176			
Equity income (loss) in joint ventures	4,736	(6,323)	(5,025)	(4,920)	(4,043)
(Gain) loss on asset sales and other(2)	1,519		(256,272)	10,729	(108,947)
Loss on early extinguishment of debt	26,601		19,574	4,359	2,478
Goodwill and other asset impairment	43,866				10,325
Non-cash linefill (gain) loss (10)	249	2,111	(46)	(346)	(3,899)
(Income) loss from discontinued operations			81	(321,155)	(84,148)
Gross margin from continuing operations	$ 434,188	$ 278,148	$ 264,923	$ 210,580	$ 163,677

(6) EBITDA represents net income (loss) before net interest expense, income taxes, and depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, impairment charges and other cash items such as the non-recurring cash derivative early termination expense. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation is similar to the Consolidated EBITDA calculation utilized within the financial covenants under our credit facility, with the exception that Adjusted EBITDA includes certain non-cash items specifically excluded under our credit facility and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Revolving Credit Facility).

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as its cost of capital and its tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as indicators of our operating performance or liquidity. The following table reconciles net income (loss) to EBITDA; and EBITDA to Adjusted EBITDA (in thousands):

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RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Net income (loss)	$ (91,637)	$ 68,059	$ 295,397	$ 280,438	$ 62,714
Adjustments:					
Interest expense[11]	89,637	41,760	31,603	87,877	101,752
Income tax expense (benefit)	(2,260)	176			
Depreciation and amortization	168,617	90,029	77,435	74,897	75,684
EBITDA	164,357	200,024	404,435	443,212	240,150
Adjustments:					
Income attributable to non-controlling interests from continuing operations[3]	(6,975)	(6,010)	(6,200)	(4,738)	(3,176)
Non-controlling interest depreciation, amortization and interest expense[12]	(2,778)				
Equity income in joint ventures	4,736	(6,323)	(5,025)	(4,920)	(4,043)
Distributions from joint ventures	7,400	7,200	4,448	11,066	4,310
Goodwill and other asset impairment	43,866				10,325
(Gain) loss on asset sales and other[13]	1,519		(256,191)	(301,373)	(162,518)
Loss on early extinguishment of debt	26,601		19,574	4,359	2,478
Non-cash (gain) loss on derivatives	28,440	(23,283)	4,538	(10,166)	74,644
Acquisition cost	20,005	15,395			
Unrecognized economic impact of acquisitions[14]	1,023	1,698			
Net cash derivative early termination expense[15]				22,401	2,260
Premium expense on derivative instruments	17,083	17,759	12,219	21,123	9,693
Non-cash compensation expense	19,344	11,636	3,274	3,484	701
Non-cash linefill (gain) loss [10]	249	2,111	(46)	(346)	(3,899)
Discontinued operations adjustments[16]				25,697	3,883
Adjusted EBITDA	$ 324,870	$ 220,207	$ 181,026	$ 209,799	$ 174,808

(7) Represents total expansion capital expenditures which includes the portion attributable to our joint interest partners.

(8) Operating data for Arkoma, WestTX and WTLPG represent 100% of the operating activity for the respective systems.

(9) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.

(10) Represents the non-cash impact of commodity price movements on pipeline linefill.

(11) Interest expense in 2010 and 2009 includes interest expense related to interest rate swaps.

(12) Represents the depreciation, amortization and interest expense included in income attributable to non-controlling interest for MarkWest Oklahoma Gas Company, LLC s (MarkWest) interest in Centrahoma.

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(13) For the year ended December 31, 2011, includes the gain on the sale of our non-controlling interest in Laurel Mountain (see Item 8. Financial Statements and Supplementary Data Note 4). For the year ended December 31, 2010, includes the gain on the sale of Elk City gathering system and related processing facilities and expenses related to the sale of our non-controlling interest in Laurel Mountain. For the year ended December 31, 2009, includes the gain on the sale of assets to Laurel Mountain and the gain on sale of the NOARK gas gathering and interstate pipeline system.

(14) Represents the earnings from the (a) TEAK Acquisition (see Item 1. Business Recent Developments) from April 1, 2013, the effective date of the purchase, through May 7, 2013, the closing date of the purchase, and (b) the Cardinal Acquisition from December 1, 2012, the effective date of the purchase, through December 20, 2012, the closing date of the purchase. These earnings were recorded as a reduction of the purchase price of each respective acquisition.

(15) During the years ended December 31, 2010 and 2009, we made net payments of $33.7 and $5.0 million, respectively, which resulted in a net cash expense recognized of $33.7 and $5.0 million, respectively, related to the early termination of derivative contracts principally entered into as proxy hedges for the prices received on the ethane and propane portion of our NGL equity volume.

(16) Includes depreciation, amortization, and interest expense; non-cash (gain) loss on derivatives; non-recurring cash derivative early termination; and premium expense on derivative instruments recorded in discontinued operations.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report.

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering, processing and treating services in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States; a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and a provider of NGL transportation services in the southwestern region of the United States.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating).

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Eagle Ford Shale play in Texas and the Anadarko, Arkoma and Permian Basins; (2) natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee; and (3) through the year ended December 31, 2011, the revenues and gain on sale related to our former 49% interest in Laurel Mountain Midstream, LLC (Laurel Mountain). Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering processing of natural gas.

Our Gathering and Processing operations own, have interests in and operate fourteen natural gas processing plants with aggregate capacity of approximately 1,490 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 11,200 miles of active natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. Our gathering systems gather natural gas from oil and natural gas wells and central delivery points and deliver to this gas to processing plants, as well as third-party pipelines.

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Our Gathering and Processing operations are all located in or near areas of abundant and long-lived natural gas production, including the Golden Trend, Mississippian Limestone and Hugoton field in the Anadarko Basin; the Woodford Shale; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin; the Barnett Shale; and the Eagle Ford Shale. Our gathering systems are connected to primarily individual well connections and, secondarily, central delivery points, which are linked to multiple wells. We believe we have significant scale in each of our primary service areas. We provide gathering, processing and treating services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering, processing and treating assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Our Transportation and Treating segment consists of (1) the Gas Treating operations; (2) a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG); and (3) through the year ended December 31, 2011, the revenues and gain on sale related to the Partnership s former 49% interest in Laurel Mountain (see Dispositions). The Gas Treating operations own seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and are located in various shale plays, including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest; and owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Gas Treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

In connection with the TEAK Acquisition (see Recent Events), we reviewed the acquired assets to determine the proper alignment of these assets within the existing reportable segments. The gas gathering and processing facilities acquired, along with their related assets, are included in the Gathering and Processing segment.

Recent Events

On January 7, 2013, we paid $6.0 million for the first of two contingent payments related to the acquisition of a gas gathering system and related assets in February 2012. We agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes were achieved on the acquired gathering system within specified periods of time. Sufficient volumes were achieved in December 2012 to meet the required volumes for the first contingent payment.

On February 11, 2013, we issued $650.0 million of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.3 million and utilized the proceeds to redeem our outstanding 8.75% senior unsecured notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of our outstanding indebtedness under our revolving credit facility (see Item 8. Financial Statements and Supplementary Data Note 13 Senior Notes). We filed a registration statement with the SEC for the exchange offer for the 5.875% Senior Notes, in satisfaction of the registration requirements of the registration rights agreement, which was declared effective on December 9, 2013. We commenced an exchange offer for the 5.875% Senior Notes on December 10, 2013 and the exchange offer was consummated on January 9, 2014 (see Item 8. Financial Statements and Supplementary Data Note 13 Senior Notes).

Prior to issuance of the 5.875% Senior Notes and in anticipation thereof, on January 28, 2013, we commenced a cash tender offer for any and all of our outstanding $365.8 million 8.75% Senior Notes, and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default

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contained in the indenture governing the 8.75% Senior Notes (8.75% Senior Notes Indenture). Approximately $268.4 million aggregate principal amount of the 8.75% Senior Notes (representing approximately 73.4% of the outstanding 8.75% Senior Notes), were validly tendered as of the expiration date of the consent solicitation. In February 2013, we accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. On March 12, 2013, we paid $105.6 million to redeem the remaining $97.3 million 8.75% Senior Notes not purchased in connection with the tender offer, plus a $6.3 million make-whole premium and $2.0 million in accrued interest. We funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

On April 12, 2013, we placed in service a new 200 MMCFD cryogenic processing plant, known as the Driver Plant, in our WestTX system in the Permian Basin of Texas, increasing the WestTX system capacity to 455 MMCFD.

On April 17, 2013, we sold 11,845,000 of our common units in a registered public offering at a price of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. We also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest (see Item 8. Financial Statements and Supplementary Data) Note 5 Common Units). We used the proceeds from this offering to fund a portion of the purchase price of the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) (the TEAK Acquisition) (see Item 8. Financial Statements and Supplementary Data Note 3 TEAK Midstream, LLC).

On April 19, 2013, we entered into an amendment to our revolving credit agreement, which among other changes:

- allowed the TEAK Acquisition to be a Permitted Investment, as defined in the credit agreement;
- did not require the joint venture interests acquired in the TEAK Acquisition to be guarantors;
- permitted the payment of cash distributions, if any, on our Class D convertible preferred units (Class D Preferred Units) so long as we have a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to $50 million; and
- modified the definition of Consolidated Funded Debt Ratio, Interest Coverage Ratio and Consolidated EBITDA to allow for an Acquisition Period whereby the terms for calculating each of these ratios have been adjusted.

On May 7, 2013, we completed a private placement of $400.0 million of our Class D Preferred Units to third party investors, at a negotiated price per unit of $29.75 for net proceeds of $397.7 million pursuant to the Class D preferred unit purchase agreement dated April 16, 2013. We also received a capital contribution from the General Partner of $8.2 million to maintain its 2.0% general partner interest in us. (See Item 8. Financial Statements and Supplementary Data Note 5 Class D Preferred Units). We used the proceeds to fund a portion of the purchase price of the TEAK Acquisition (see Item 8. Financial Statements and Supplementary Data Note 3 TEAK Midstream, LLC).

On May 7, 2013, we completed the TEAK Acquisition for $974.7 million in cash, including final purchase price adjustments, less cash received (see Item 8. Financial Statements and Supplementary Data Note 3 TEAK Midstream, LLC). The assets acquired, which are referred to as the SouthTX assets, include the following gas gathering and processing facilities in the Eagle Ford shale region of south Texas:

- the Silver Oak I plant, which is a 200 MMCFD cryogenic processing facility;

- a second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, expected to be in service the second quarter of 2014;

- 265 miles of primarily 20-24 inch gathering and residue lines;

- approximately 275 miles of low pressure gathering lines;

- a 75% interest in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle), which owns a 62 mile, 24-inch gathering line;

- a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford), which owns a 45 mile, 16-inch gathering pipeline; a 71 mile 24-inch gathering line; and a 50 mile residue pipeline; and

- a 50% interest in T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen), which owns a cogeneration facility.

On May 10, 2013, we issued $400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes) in a private placement transaction. The 4.75% Senior Notes were issued at par. We received net proceeds of $391.2 million after underwriting commissions and other transactions costs (see Item 8. Financial Statements and Supplementary Data Note 13 Senior Notes). We utilized the proceeds repay a portion of our outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Item 8. Financial Statements and Supplementary Data Note 3 TEAK Midstream, LLC). We filed a registration statement with the SEC for the exchange offer of the 4.75% Senior Notes, in satisfaction of the registration requirements of the registration rights agreement, which was declared effective on December 9, 2013. We commenced an exchange offer for the 4.75% Senior Notes on December 10, 2013 and the exchange offer was consummated on January 9, 2014 (see Item 8. Financial Statements and Supplementary Data Note 13 Senior Notes).

We filed a registration statement with the SEC for the exchange offer for $500.0 million of the 6.625% unsecured senior notes due October 2020 (6.625% Senior Notes), in satisfaction of the registration requirements of the registration rights agreement, which was declared effective on September 17, 2013. We commenced an exchange offer for the 6.625% Senior Notes on September 18, 2013 and the exchange offer was consummated on October 16, 2013. Pursuant to the terms of the registration rights agreements relating to the 6.625% Senior Notes, because the exchange offer was not completed by the September 22, 2013 deadline for the 6.625% Senior Notes issued in September 2012, we incurred a 0.25% additional interest penalty of $52 thousand for the period from September 23, 2013 through consummation of the exchange offer on October 16, 2013 (see Item 8. Financial Statements and Supplementary Data Note 13 Senior Notes).

Subsequent Events

On January 28, 2014, we declared a cash distribution of $0.62 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $56.1 million distribution, including $6.1 million to the General Partner for its general partner interest and incentive distribution rights, was paid on February 14, 2014 to unitholders of record at the close of business on February 7, 2014 (see Item 8. Financial Statements and Supplementary Data see Note 5). Based on this declaration, we also distributed approximately 275,000 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution for the quarter ended December 31, 2013.

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Acquisitions

In May 2011, we acquired a 20% interest in WTLPG from Buckeye Partners, L.P. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu for fractionation and is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest.

In February 2012, we acquired a gas gathering system and related assets at our WestOK system for an initial net purchase price of $19.0 million. We agreed to pay up to an additional $12.0 million, payable in two equal amounts, subject to delivery of certain minimum volumes of natural gas from a specified area and within certain specified time periods. In connection with this acquisition, we received assignment of the gas purchase agreements for natural gas then currently gathered on the acquired system.

In June 2012, we acquired a gas gathering system and related assets in the Barnett Shale in Tarrant County, Texas for an initial net purchase price of $18.0 million. The system is used to facilitate gathering of newly-acquired natural gas production of our affiliate, Atlas Resource Partners, L.P. (NYSE: ARP) (ARP). We do not directly gather natural gas for ARP. Rather, we gather natural gas for a third party that purchases ARP s production. ARP s general partner is wholly-owned by ATLS, and two members of our General Partner s managing board are members of ARP s board of directors.

In December 2012, we acquired 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $598.9 million in cash, including purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies represented the majority of the operating assets of Cardinal and include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas (which are referenced as the Arkoma system included within the SouthOK system) as follows:

- the Tupelo plant, which is a 120 MMCFD cryogenic processing facility;
- approximately 60 miles of gathering pipeline;
- the East Rockpile treating facility, a 250 GPM amine treating plant;
- a fixed fee contract gas treating business that includes 15 amine treating plants and two propane refrigeration plants; and
- a 60% interest in a joint venture known as Centrahoma Processing, LLC (Centrahoma). The remaining 40% interest is owned by MarkWest Oklahoma Gas Company, LLC, (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE). Centrahoma owns the following assets:
  - the Coalgate and Atoka plants, which are cryogenic processing facilities with a combined current processing capacity of approximately 100 MMCFD;

- the prospective Stonewall plant, for which construction has been approved, with anticipated processing capacity of 120 MMCFD; and

- 15 miles of NGL pipeline.

In May 2013, we completed the TEAK Acquisition for $974.7 million in cash, including final purchase price adjustments, less cash received (see Recent Events).

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Dispositions

In February 2011, we completed the sale of our 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources for $409.5 million in cash, net of expenses and adjustments and recognized a gain of $254.1 million.

Recent Trends and Uncertainties

The midstream natural gas industry links the exploration and production of natural gas and the delivery of its components to end-use markets and provides natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services. This industry group is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

We face competition in obtaining natural gas supplies for our processing and related services operations. Competition for natural gas supplies is based primarily on the location of gas gathering facilities and gas processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price, delivery capabilities, quality of assets, flexibility, service history and maintenance of high-quality customer relationships. Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to, and in some cases lower than, ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. We believe the primary difference between us and some of our competitors is that we provide an integrated and responsive package of midstream services, while some of our competitors provide only certain services. We believe offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our regions of operations.

As a result of our POP and Keep-Whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas, NGLs and crude oil (see Item 8. Financial Statements and Supplementary Data Note 2 Revenue Recognition). We believe future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. However, energy market uncertainty has negatively impacted North American drilling activity in the past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered, processed and treated.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity-based derivative instruments such as natural gas, crude oil and NGL financial contracts to hedge a portion of the value of our assets and operations from such price risks. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk for further discussion of commodity price risk.

Currently, there is a significant level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and ability to raise additional capital, and an increase in the volatility of the price of our common units.

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How We Evaluate Our Operations

Our principal revenue is generated from the gathering, processing and treating of natural gas; the sale of natural gas, NGLs and condensate; the transportation of NGLs; and the leasing of gas treating facilities. (See Item 8. Financial Statements and Supplementary Data Note 2 Revenue Recognition for further discussion of contractual revenue arrangements). Our profitability is a function of the difference between the revenues we receive and the costs associated with conducting our operations, including the cost of natural gas, NGLs and condensate we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Variables that affect our profitability are:

- the volumes of natural gas we gather, process and treat, which in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas the wells produce, and the demand for natural gas, NGLs and condensate;
- the price of the natural gas we gather; process and treat; and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent and northeastern areas of the United States;
- the NGL and BTU content of the gas gathered and processed;
- the contract terms with each producer; and
- the efficiency of our gathering systems and processing and treating plants.

Our management uses a variety of financial measures and operational measurements other than our GAAP financial statements to analyze our performance. These include: (1) volumes, (2) operating expenses and (3) the following non-GAAP measures gross margin, adjusted EBITDA and distributable cash flow. Our management views these measures as important performance measures of core profitability for our operations and as key components of our internal financial reporting. We believe investors benefit from having access to the same financial measures that our management uses.

Volumes. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering, processing and treating systems. This is achieved by connecting new wells and adding new volumes in existing areas of production. Our performance at our plants is also significantly impacted by the quality of the natural gas we process, the NGL content of the natural gas and the plant s recovery capability. In addition, we monitor fuel consumption and losses because they have a significant impact on the gross margin realized from our processing operations.

Operating Expenses. Plant operating, transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, ad valorem taxes and other overhead costs.

Gross Margins. We define gross margin as natural gas and liquids sales revenue plus transportation, processing and other fee revenues less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas, NGLs and condensate we purchase from third parties. Gross margin, as we define it, does not include plant operating expenses; transportation and compression expenses; and derivative gain (loss) related to undesignated hedges, as movements in gross margin generally do not result in directly correlated movements in these categories.

Gross margin is a non-GAAP measure. The GAAP measure most directly comparable to gross margin is net income. Gross margin is not an alternative to GAAP net income and has important limitations as an analytical tool. Investors should not consider gross margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of gross margin may not be comparable to gross margin measures of other companies, thereby diminishing its utility (see Item 6. Selected Financials for a reconciliation of net income to gross margin).

EBITDA and Adjusted EBITDA. EBITDA represents net income (loss) before interest expense, income taxes, depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, impairment charges and other cash items such as non-recurring cash derivative early termination expense. The GAAP measure most directly comparable to EBITDA and Adjusted EBITDA is net income. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation is similar to the Consolidated EBITDA calculation utilized within the financial covenants under our credit facility, with the exception that Adjusted EBITDA includes certain non-cash items specifically excluded under our credit facility and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see Revolving Credit Facility).

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as cost of capital and historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as indicators of our operating performance or liquidity. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our unit holders. (See Item 6. Selected Financials for a reconciliation of net income to EBITDA and Adjusted EBITDA).

Distributable Cash Flow. We define distributable cash flow as net income plus tax, depreciation and amortization; amortization of deferred financing costs included in interest expense; and non-cash gain (losses) on derivative contracts, less income attributable to non-controlling interests, preferred unit dividends, maintenance capital expenditures, gain (losses) on asset sales and other non-cash gain (losses).

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

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The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income or GAAP cash flows from operating activities. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following table reconciles the non-GAAP financial measurement distributable cash flow used by management to its most directly comparable GAAP measure for the years ended December 31, 2013, 2012 and 2011 (in thousands):

RECONCILIATION OF DISTRIBUTABLE CASH FLOW

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in thousands)	
Adjusted EBITDA[1]	$ 324,870	$ 220,207	$ 181,026
Interest expense	(89,637)	(41,760)	(31,603)
Amortization of deferred finance costs	6,965	4,672	4,480
Preferred dividend obligation			(389)
Proceeds remaining from asset sale[2]			5,850
Premium expense on derivative instruments	(17,083)	(17,759)	(12,219)
Other costs		(326)	1,040
Maintenance capital[3]	(21,252)	(19,021)	(18,247)
Distributable Cash Flow	$ 203,863	$ 146,013	$ 129,938

(1) See Item 6. Selected Financials Reconciliation of Net Income to EBITDA and Adjusted EBITDA.

(2) Net proceeds remaining from the sale of Laurel Mountain after repayment of the amount outstanding on our revolving credit facility, redemption of our 8.125% Senior Notes due 2015 and purchase of certain 8.75% Senior Notes.

(3) Net of non-controlling interest maintenance capital of $667 thousand for the year ended December 31, 2013.

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Results of Operations

The following table illustrates selected pricing before the effect of derivatives and volumetric information for the periods indicated:

	Years Ended December 31,				
	2013	2012	Percent Change	2011	Percent Change
Pricing:					
Weighted average prices:					
NGL price per gallon Conway hub	$ 0.82	$ 0.78	5.1 %	$ 1.08	(27.8)%
NGL price per gallon Mt. Belvieu hub	0.85	0.96	(11.5)%	1.31	(26.7)%
Natural gas sales ($/Mcf):					
SouthOK/Velma	3.46	2.60	33.1 %	3.86	(32.6)%
WestOK	3.42	2.66	28.6 %	3.87	(31.3)%
WestTX	3.38	2.54	33.1 %	3.84	(33.9)%
Weighted Average	3.44	2.62	31.3 %	3.86	(32.1)%
NGL sales ($/gallon):					
SouthOK/Velma	0.79	0.78	1.3 %	1.11	(29.7)%
SouthOK/Arkoma	0.78		%		%
SouthTX	0.79		%		
WestOK	1.04	0.89	16.9 %	1.10	(19.1)%
WestTX	0.92	0.98	(6.1)%	1.33	(26.3)%
Weighted Average	0.91	0.90	1.1 %	1.20	(25.0)%
Condensate sales ($/barrel):					
SouthOK/Velma	96.23	94.82	1.5 %	94.35	0.5 %
SouthOK/Arkoma	88.26				
SouthTX	93.75				
WestOK	87.17	84.76	2.8 %	86.63	(2.2)%
WestTX	98.55	89.40	10.2 %	92.84	(3.7)%
Weighted Average	91.90	87.88	4.6 %	90.65	(3.1)%

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	Years Ended December 31,				
	2013	2012	Percent Change	2011	Percent Change
Operating data:					
SouthOK system:					
Velma:					
Gathered gas volume (MCFD)	147,300	128,548	14.59 %	103,328	24.41 %
Processed gas volume (MCFD)	140,571	114,421	22.85 %	98,126	16.61 %
Residue Gas volume (MCFD)	117,079	100,711	16.25 %	80,330	25.37 %
NGL volume (BPD)	16,067	13,850	16.01 %	11,433	21.14 %
Condensate volume (BPD)	379	409	(7.33)%	423	(3.31)%
Arkoma[(1)]:					
Gathered gas volume (MCFD)	258,773	222,045	16.54 %		
Processed gas volume (MCFD)	238,161	211,032	12.86 %		
Residue Gas volume (MCFD)	206,946	174,604	18.52 %		
NGL volume (BPD)	19,021	16,138	17.86 %		
Condensate volume (BPD)	146	122	19.67 %		
SouthTX system:					
Gathered gas volume (MCFD)	132,826				
Processed gas volume (MCFD)	131,745				
Residue Gas volume (MCFD)	105,207				
NGL volume (BPD)	16,711				
Condensate volume (BPD)	77				
WestOK system:					
Gathered gas volume (MCFD)	500,756	369,035	35.69 %	268,329	37.53 %
Processed gas volume (MCFD)	475,441	348,041	36.60 %	254,394	36.81 %
Residue Gas volume (MCFD)	438,611	322,751	35.90 %	230,907	39.78 %
NGL volume (BPD)	20,971	14,505	44.58 %	13,635	6.38 %
Condensate volume (BPD)	1,887	1,360	38.75 %	898	51.45 %
WestTX system[(1)]:					
Gathered gas volume (MCFD)	357,524	275,946	29.56 %	212,775	29.69 %
Processed gas volume (MCFD)	328,678	249,221	31.88 %	196,412	26.89 %
Residue Gas volume (MCFD)	244,294	179,539	36.07 %	133,857	34.13 %
NGL volume (BPD)	41,920	32,314	29.73 %	29,052	11.23 %
Condensate volume (BPD)	1,657	1,524	8.73 %	1,500	1.60 %
Barnett system:					
Average throughput volume (MCFD)	21,356	22,935	(6.88)%		
Tennessee system:					
Average throughput volume (MCFD)	8,300	8,487	(2.20)%	7,698	10.25 %
WTLPG system[(1)]:					
Average throughput volume (BPD)	245,599	249,533	(1.58)%	229,673	8.65 %

(1) Operating data for Arkoma, WestTX and WTLPG represent 100% of operating activity for the respective systems. Arkoma gathered volumes include volumes gathered by MarkWest and processed through the Arkoma facilities.

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

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2013 and 2012 (in thousands):

	Years Ended December 31, 2013	Years Ended December 31, 2012	Variance	Percent Change
Gross margin[1]				
Natural gas and liquids sales	$ 1,959,144	$ 1,137,261	$ 821,883	72.3%
Transportation, processing and other fees	165,177	66,722	98,455	147.6%
Less: non-cash line fill loss[2]	(249)	(2,111)	1,862	88.2%
Less: natural gas and liquids cost of sales	1,690,382	927,946	762,436	82.2%
Gross margin	434,188	278,148	156,040	56.1%
Gross margin %	20.4%	23.1%		
Expenses:				
Operating expenses	94,527	62,098	32,429	52.2%
General and administrative[3]	60,856	47,206	13,650	28.9%
Other costs	20,005	15,069	4,936	32.8%
Depreciation and amortization	168,617	90,029	78,588	87.3%
Interest expense	89,637	41,760	47,877	114.6%
Total expenses	433,642	256,162	177,480	69.3%
Other income items:				
Derivative gain (loss), net	(28,764)	31,940	(60,704)	(190.1)%
Other income, net	11,292	10,097	1,195	11.8%
Non-cash line fill loss[2]	(249)	(2,111)	1,862	88.2%
Equity income (loss) in joint ventures	(4,736)	6,323	(11,059)	(174.9)%
Goodwill impairment loss	(43,866)		(43,866)	(100.0)%
Loss on asset disposition	(1,519)		(1,519)	(100.0)%
Loss on early extinguishment of debt	(26,601)		(26,601)	(100.0)%
Income tax benefit (expense)	2,260	(176)	2,436	100.0%
Income attributable to non-controlling interests[4]	(6,975)	(6,010)	(965)	(16.1)%
Preferred unit imputed dividend effect	(29,485)		(29,485)	(100.0)%
Preferred unit dividends in kind	(23,583)		(23,583)	(100.0)%
Net income (loss) attributable to common limited partners and General Partner	$ (151,680)	$ 62,049	$ (213,729)	(344.5)%
Non-GAAP financial data:				
EBITDA[1]	$ 164,357	$ 200,024	$ (35,667)	(17.8)%
Adjusted EBITDA[1]	324,870	220,207	104,663	47.5%
Distributable cash flow[1]	203,863	146,013	57,850	39.6%

(1) Gross margin, EBITDA, Adjusted EBITDA and distributable cash flow are non-GAAP financial measures (see How We Evaluate Our Operations Reconciliation of Distributable Cash Flow and Item 6. Selected Financials Reconciliation of Net Income to EBITDA and Adjusted EBITDA).
(2) Includes the non-cash impact of commodity price movements on pipeline linefill.
(3) General and administrative also includes compensation reimbursement to affiliates.
(4) Represents Anadarko Petroleum Corporation s (Anadarko NYSE: APC) non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest s non-controlling interest in Centrahoma.

Gross margin

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the year ended December 31, 2013 increased primarily due to higher production volumes, including the new volumes from the SouthTX system due to the TEAK Acquisition (see Acquisitions).

- Volumes on the SouthOK system for the year ended December 31, 2013 increased from the prior year period volumes primarily due to increased production from the V-60 plant, which was placed into service in July 2012 and from the new volumes from the Arkoma system due to the Cardinal Acquisition (see Acquisitions);

- Volumes on the WestOK system increased for the year ended December 31, 2013 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and the start-up of the Waynoka II plant, which was placed into service in September 2012; and

- WestTX system gathering and processing volumes for the year ended December 31, 2013 increased compared to the prior year period due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) and others as a result of their continued drilling programs; and the start-up of the Driver plant in April 2013 (see Recent Events).

Transportation, processing and other fees for the year ended December 31, 2013 increased primarily due to $42.4 million in additional fee-based revenues generated on the SouthOK system due to the Arkoma assets acquired in the Cardinal Acquisition (see Acquisitions); and $24.7 million in additional fee-based revenues generated on the SouthTX system acquired in the TEAK Acquisition (see Acquisitions); and increased processing fee revenue of $13.9 million on the WestOK system related to the increased volumes gathered on the systems.

Expenses

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the year ended December 31, 2013 increased mainly due to $11.7 million in additional expenses from the Arkoma plants, within the SouthOK system, acquired in the Cardinal Acquisition (see Acquisitions); $6.9 million in additional expenses from the SouthTX systems acquired in the TEAK Acquisition (see Acquisitions); a $7.0 million increase on the WestOK system primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin ; and a $4.5 million increase on the WestTX system primarily due to increased gathered volumes from Pioneer Natural Resources Company and other producers.

General and administrative expense, including amounts reimbursed to affiliates, increased for the year ended December 31, 2013 mainly due to a $7.7 million increase in share-based compensation related to phantom units granted to employees (see Item 8: Financial Statements and Supplementary Data Note 16); and a $3.6 million increase in salaries and wages partially due to the increase in the number of employees as a result of the Cardinal and TEAK Acquisitions (see Acquisitions).

Other costs for the year ended December 31, 2013 increased mainly due to $19.3 million in acquisition costs related to the TEAK Acquisition in the current year compared to $15.4 million in acquisition costs related to the Cardinal

Acquisition in the prior year (see Acquisitions).

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Depreciation and amortization expense for the year ended December 31, 2013 increased primarily due to $31.8 million additional expense related to assets acquired in the Cardinal Acquisition (see Acquisitions); $26.9 million additional expense related to assets acquired in the TEAK Acquisition (see Acquisitions) and due to growth capital expenditures incurred subsequent to December 31, 2012.

Interest expense for the year ended December 31, 2013 increased primarily due to $33.9 million additional interest related to the 5.875% Senior Notes; $26.7 million increase in interest expense associated with 6.625% Senior Notes; and $12.1 million additional interest related to the 4.75% Senior Notes; partially offset by $27.0 million reduced interest on the 8.75% Senior Notes. The increase in the interest on the 5.875% Senior Notes and the 4.75% Senior Notes is due to their issuance in 2013 (see Senior Notes). The increase in the interest on the 6.625% Senior Notes is due to an additional issuance of $175.0 million in December 2012. The decrease in the interest for the 8.75% Senior Notes is due to their redemption in February 2013 (see Senior Notes).

Other income items

Derivative gain (loss), net for the year ended December 31, 2013 was unfavorable primarily due to a $49.4 million unfavorable variance on the non-cash fair value revaluation of commodity derivative contracts in the current period compared to the prior year period mainly due to a $20.9 million gain in the prior year period resulting from a decrease in prices during the prior year period; and a $28.4 million loss in the current year period resulting from an increase in prices during the current year period. We recognized a $16.8 million mark-to-market loss and a $27.3 million mark-to-market gain on derivatives that were valued based upon unobservable inputs for the years ended December 31, 2013 and 2012, respectively.

Other income, net for the year ended December 31, 2013 had a favorable variance primarily due to a $1.0 million settlement of business interruption insurance related to a loss of revenue in our WestOK system in May 2011 due to storm damage at the Chester plant.

Non-cash line fill loss had a favorable variance for the year ended December 31, 2013 compared to the prior year period primarily due to a decrease in forward curve prices during the prior year period.

Equity income (loss) in joint ventures decreased for the year ended December 31, 2013 primarily due to a $9.7 million loss in the current period from the SouthTX equity method investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense.

Goodwill impairment loss of $43.9 million in the current year pertained to an impairment of goodwill related to our contract gas treating business acquired during the Cardinal Acquisition (see Item 8: Financial Statements and Supplementary Data Note 7)

Loss on asset disposition in the current year period pertained to management s decision to not pursue a project to lay pipe in an area where acquired rights of way had expired in the SouthOK system.

Loss on early extinguishment of debt for the year ended December 31, 2013 represents $17.5 million premiums paid; $8.0 million consent payment made; and $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium related to the redemption of the 8.75% Senior Notes (see Senior Notes).

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Income tax benefit for the year ended December 31, 2013 represents the accrued income tax related to the income earned on APL Arkoma, Inc., which was acquired as part of the Cardinal Acquisition (see Acquisitions).

Income attributable to non-controlling interests increased primarily due to Anadarko s non-controlling interest in higher net income for the WestOK and WestTX joint ventures. The increase in net income of the WestOK and WestTX joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the current period represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 8: Financial Statements and Supplementary Data Note 5 Preferred Units).

Preferred unit dividends for the current period represent the distributions to the Class D Preferred Units, which have been declared. For the current period these distributions are paid in kind (see Item 8: Financial Statements and Supplementary Data Note 5 Preferred Units).

Non-GAAP financial data

Adjusted EBITDA had a favorable variance for the year ended December 31, 2013 compared to the prior year period mainly due to the improved gross margin variance, as discussed above in Gross Margin , partially offset by higher operating expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the year ended December 31, 2013 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses.

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

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2012 and 2011 (in thousands):

	Years Ended December 31			Percent
	2012	2011	Variance	Change
Gross margin[(1)]				
Natural gas and liquids sales	$ 1,137,261	$ 1,268,195	$ (130,934)	(10.3)%
Transportation, processing and other fees	66,722	43,799	22,923	52.3%
Less: natural gas and liquids cost of sales	927,946	1,047,025	119,079	11.4%
Less: non-cash linefill gain (loss)[(2)]	(2,111)	46	2,157	4,689.1%
Gross margin	278,148	264,923	13,225	5.0%
Gross margin %	23.1%	20.2%		
Expenses:				
Operating expenses	62,098	55,519	6,579	11.8%
General and administrative[(3)]	47,206	36,357	10,849	29.8%
Other costs	15,069	1,040	14,029	1,348.9%
Depreciation and amortization	90,029	77,435	12,594	16.3%
Interest expense	41,760	31,603	10,157	32.1%
Total expenses	256,162	201,954	54,208	26.8%
Other income items:				
Derivative gain (loss), net	31,940	(20,452)	52,392	256.2%
Other income, net	10,097	11,192	(1,095)	(9.8)%
Non-cash linefill gain (loss)[(2)]	(2,111)	46	(2,157)	(4,689.1)%
Equity income in joint venture	6,323	5,025	1,298	25.8%
Gain on asset sales and other[(4)]		256,191	(256,191)	(100.0)%
Loss on early extinguishment of debt		(19,574)	19,574	100.0%
Income tax expense	(176)		(176)	100.0%
Income attributable to non-controlling interests[(5)]	(6,010)	(6,200)	190	3.1%
Preferred unit dividends		(389)	389	100.0%
Net income attributable to common limited partners and General Partner	$ 62,049	$ 288,808	$ (226,759)	(78.5)%
Non-GAAP financial data:				
EBITDA[(1)]	$ 200,024	$ 404,435	$ (204,411)	(50.5)%
Adjusted EBITDA[(1)]	220,207	181,026	39,181	21.6%
Distributable cash flow[(1)]	146,013	129,938	16,075	12.4%

(1)

Gross margin, EBITDA, Adjusted EBITDA and distributable cash flow are non-GAAP financial measures (see How We Evaluate Our Operations and Item 6. Selected Financials Reconciliation of net income to EBITDA and Adjusted EBITDA).

(2) Includes the non-cash impact of commodity price movements on pipeline linefill.

(3) General and administrative also includes compensation reimbursement to affiliates.

(4) Represents the gain on sale Laurel Mountain and an adjustment to the gain on sale of our Elk City system (see Dispositions).

(5) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest s non-controlling interest in Centrahoma.

Gross margin

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the year ended December 31, 2012 increased primarily due to higher production volumes offset by lower natural gas and NGL sales prices.

Volumes on the SouthOK system increased for the year ended December 31, 2012 compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma gas gathering pipeline and the start-up of the Velma V-60 expansion plant in June 2012.

Volumes on the WestOK system increased for the year ended December 31, 2012 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and the start-up of the Waynoka II plant.

WestTX system gathering and processing volumes for the year ended December 31, 2012 increased compared to the prior year period due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) as a result of their continued drilling program.

Transportation, processing and other fees for the year ended December 31, 2012 increased primarily due to increased processing fee revenue on the WestOK and Velma systems related to the increased volumes gathered on the systems.

Expenses

Operating expenses, comprised of plant operating expenses; and transportation and compression expenses for the year ended December 31, 2012 increased primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin.

General and administrative expense, including amounts reimbursed to affiliates, increased for the year ended December 31, 2012 mainly due to increased non-cash compensation expense and an increase in the allocation from our General Partner for compensation and benefits related to its employees who perform services for us.

Other costs for the year ended December 31, 2012 increased mainly due to $15.4 million in acquisition costs related to the Cardinal Acquisition (see Acquisitions).

Depreciation and amortization expense for the year ended December 31, 2012 increased primarily due to expansion capital expenditures incurred subsequent to December 31, 2011.

Interest expense for the year ended December 31, 2012 increased primarily due to a $10.8 million increase in interest expense associated with the 8.75% Senior Notes; $5.8 million in additional interest expense associated with the 6.625% Senior Notes; and a $2.7 million increase in interest associated with the revolving credit facility; partially offset by a $6.0 million decrease in interest expense associated with the 8.125% Senior Notes and a $3.5 million increase in capitalized interest. The increased interest expense on the 8.75% Senior Notes is due to the issuance of additional 8.75% Senior Notes in November 2011. The additional interest expense on the 6.625% Senior Notes is due to the issuance of $325.0 million 6.625% Senior Notes in September 2012. The increased interest expense associated with the revolving credit facility is due to additional borrowings since December 31, 2011 to cover capital expenditures and to fund the Cardinal Acquisition (see Acquisitions). The lower interest expense on our 8.125% Senior Notes is due to the redemption of the 8.125% Senior Notes in April 2011 with proceeds from the sale of our 49% non-controlling interest in Laurel Mountain (see Dispositions). The increased capitalized interest is due to the increased capital expenditures in the current period (see Capital Requirements).

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Other income items

Derivative gain (loss), net had a favorable variance for the year ended December 31, 2012 mainly due to a $28.3 million favorable variance on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period; combined with a $27.1 million favorable variance for realized settlements in the current period compared to the prior year period mainly as a result of lower NGL prices. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations; and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management s estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 8: Financial Statements and Supplementary Data Note 11 for further discussion of derivative instrument valuations). We recognized a $27.3 million mark-to-market gain and a $20.6 million mark-to-market loss for derivatives, which were valued upon unobservable inputs, for the years ended December 31, 2012 and 2011, respectively. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Other income, net for the year ended December 31, 2012 decreased compared to the prior year period primarily due to lower interest income, which is partially due to the December 2011 settlement of a note receivable from The Williams Companies, Inc. (NYSE: WMB) related to our former 49% non-controlling ownership interest in Laurel Mountain, which we sold in February 2011 (see Dispositions).

Non-cash linefill gain (loss) had an unfavorable variance for the year ended December 31, 2012 compared to the prior year period primarily due to a loss recognized on the revaluation of linefill in the current year period due to decreased NGL prices.

Equity income in joint venture increased for the year ended December 31, 2012 primarily due to a full year of equity earnings generated in the current period from our 20% ownership interest in WTPLG compared to equity earnings for only a portion of the prior year period due to the purchase of our ownership interest in May 2011.

Loss on early extinguishment of debt for the year ended December 31, 2011 represents the premium paid for the redemption of the 8.125% Senior Notes and the recognition of deferred finance costs related to the redemption.

Income tax expense for the year ended December 31, 2012 represents the accrued income tax related to the eleven days of income earned on APL Arkoma, Inc., which was acquired as part of the Cardinal Acquisition.

Preferred unit dividends for the year ended December 31, 2011 represent dividends paid on the then outstanding 8,000 units of 12% Cumulative Class C Preferred Units, which were redeemed in 2011.

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Non-GAAP financial data

EBITDA was lower for the year ended December 31, 2012 compared to the prior year period mainly due to the gain on sale of assets recognized during the year ended December 31, 2011, as discussed above in Other income items ; partially offset by the favorable derivative gain recognized during the year ended December 31, 2012, as discussed above in Other income items ; and the impact of the loss on early extinguishment of debt recorded in the prior year period as discussed above in Other income items .

Adjusted EBITDA had a favorable variance for the year ended December 31, 2012 compared to the prior year period mainly due to the favorable variance of the cash portion of the derivative gain, as discussed above in Other income items ; combined with a higher gross margin variance, as discussed above in Gross margin .

Distributable cash flow had a favorable variance for the year ended December 31, 2012 compared to the prior year period due to the favorable variance of Adjusted EBITDA, partially offset by higher interest expense, as discussed above in Expenses ; $5.9 million net proceeds in the prior year period, which was remaining from the sale of Laurel Mountain after repayment of debt; and higher premiums paid for derivative options in the current period compared to the prior year period.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our revolving credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our common unitholders and General Partner. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and additional capital raising; and
- debt principal payments through operating cash flows and refinancings as they become due, or by the issuance of additional limited partner units or asset sales.

At December 31, 2013, we had $152.0 million outstanding borrowings under our $600.0 million senior secured revolving credit facility and $0.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with $477.9 million of remaining committed capacity under the revolving credit facility, (see Revolving Credit Facility). We were in compli