ATLAS PIPELINE PARTNERS LP
Form 10-K
February 20, 2014
Table of Contents

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	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

Park Place Corporate Center One **1000 Commerce Drive, 4th Floor** **Pittsburgh, Pennsylvania**	**15275-1011**
(Address of principal executive office)	**(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

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO ANNUAL REPORT

ON FORM 10-K

		Page
Forward Looking Statements		3
Glossary of Terms		4
PART I.		
Item 1.	Business	5
Item 1A.	Risk Factors	34
Item 1B.	Unresolved Staff Comments	54
Item 2.	Properties	54
Item 3.	Legal Proceedings	54
Item 4.	Mine Safety Disclosure	54
PART II.		
Item 5.	Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	55
Item 6.	Selected Financial Data	56
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	64
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	96
Item 8.	Financial Statements and Supplementary Data	98
Item 9.	Changes In and Disagreements with Accountants on Accounting and Financial Disclosure Disclosure	159
Item 9A.	Controls and Procedures	159
Item 9B.	Other Information	159
PART III.		
Item 10.	Directors, Executive Officers and Corporate Governance	163
Item 11.	Executive Compensation	170
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	191
Item 13.	Certain Relationships and Related Transactions, and Director Independence	194
Item 14.	Principal Accountant Fees and Services	196
PART IV.		

Item 15.	Exhibits and Financial Statement Schedules	197
SIGNATURES		200

Table of Contents

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.

Table of Contents

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

Table of Contents

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:

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

8

Table of Contents

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.

9

Table of Contents

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.

Table of Contents

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.

Table of Contents

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).

Table of Contents

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).

Table of Contents

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 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.

16

Table of Contents

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

17

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 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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

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.

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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;

- 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;

Table of Contents

- 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.

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

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 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

52

Table of Contents

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.

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.

Table of Contents

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:

Table of Contents

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.

Table of Contents

	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

Table of Contents

	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

	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

Table of Contents

	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.

60

Table of Contents

(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

61

(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):

Table of Contents

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.

Table of Contents

(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.

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

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.

Table of Contents

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).

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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)%

Table of Contents

	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.

Table of Contents

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).

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).

77

Table of Contents

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.

Table of Contents

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).

Table of Contents

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.

Table of Contents

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 compliance with the credit facility s covenants at December 31, 2013. We had a working capital deficit of $78.4 million at December 31, 2013 compared with a $33.4 million working capital deficit at December 31, 2012. We believe we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flows. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Instability in the financial markets, as a result of recession or otherwise, may cause volatility in the markets and may impact the availability of funds from those markets. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flows from operations and our revolving credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain additional capital will be available to the extent required and on acceptable terms.

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

The following table details the variances between the years ended 2013 and 2012 for cash flows (in thousands):

	Year Ended December 31, 2013	2012	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 210,844	$ 174,638	$ 36,206	20.7%
Investing activities	(1,443,083)	(1,006,641)	(436,442)	(43.4)%
Financing activities	1,233,755	835,233	398,522	47.7%
Net change in cash and cash equivalents	$ 1,516	$ 3,230	$ (1,714)	

Net cash provided by operating activities for the year ended December 31, 2013 increased compared to the prior year period due to a $60.0 million increase in net earnings from continuing operations excluding non-cash charges offset by a $23.8 million unfavorable variance in the change in working capital. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased gross margins from the sale of natural gas and NGLs offset by an increase in interest expense (see Results of Operations). The change in working capital is mainly due to a $16.3 million increase in accrued interest primarily related to our Senior Notes (see Senior Notes), and due to a net increase in working capital deficit related to the Cardinal and TEAK Acquisitions (see Acquisitions).

Net cash used in investing activities for the year ended December 31, 2013 increased compared to the prior year period mainly due to the $974.7 million net cash paid for the TEAK Acquisition (see Acquisitions); a $77.0 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under Capital Requirements); and a $13.4 million increase in contributions to equity method joint ventures (see Item 8. Financial Statements and Supplementary Data Note 4 Equity Method Investments). These increases in net cash used in investing activities were partially offset by $633.6 million net cash paid for acquisition of assets in the prior period, including the Cardinal Acquisition (see Acquisitions).

Net cash provided by financing activities for the year ended December 31, 2013 increased compared to the prior year period mainly due to (i) $637.3 million provided by the issuance of the 5.875% Senior Notes; (ii) $391.2 million provided by the issuance of the 4.75% Senior Notes (see Senior Notes); (iii) $397.7 million provided by the issuance of Class D Preferred Units (see Preferred Unit Offerings); (iv) an increase of $128.8 million provided by the sale of common units under our equity distribution program (see Common Unit Offerings); and (v) an increase of $75.9 million provided by the issuance of common units related to acquisitions (see Common Unit Offerings). The increases were partially offset by the $391.4 million redemption of the 8.75% Senior Notes, including the cost of early retirement of debt; $495.4 million provided by the issuance of the 6.625% Senior Notes in the prior year; a $151.0 million, net increase in the prior period to outstanding borrowings on the revolving credit facility; and a $141.0 million, net decrease in the current period to outstanding borrowings on the

Table of Contents

revolving credit facility. The gross amount of borrowings and repayments under the revolving credit facility included within net cash provided by (used in) financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of (i) cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facility, and (ii) payments, which generally occur throughout the period and increase borrowings under the revolving credit facility, which is generally common practice for the industry.

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

The following table details the variances between the years ended 2012 and 2011 for cash flows (in thousands):

	Years Ended December 31, 2012	2011	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 174,638	$ 102,867	$ 71,771	69.8%
Investing activities	(1,006,641)	67,763	(1,074,404)	(1,585.5)%
Financing activities	835,233	(170,626)	1,005,859	589.5%
Net change in cash and cash equivalents	$ 3,230	$ 4	$ 3,226	

Net cash provided by operating activities for the year ended December 31, 2012 increased compared to the prior year period due to a $41.7 million increase in net earnings from continuing operations excluding non-cash charges and a $30.1 million favorable variance in the change in working capital. The increase in net earnings is primarily due to favorable transportation, processing and other fees from increased gathered and processed volumes; favorable derivative settlements in the current period compared to the prior year period; and increased distributions received from WTLPG (see Results of Operations).

Net cash provided by (used in) investing activities for the year ended December 31, 2012 had an unfavorable variance compared to the prior year period mainly due to (1) $633.6 million net cash paid for acquisition of assets in the current period, including the Cardinal Acquisition (see Acquisitions); (2) net proceeds of $403.6 million received from the sale of Laurel Mountain in the prior period (see Dispositions); and (3) a $128.1 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under Capital Requirements), partially offset by $85.0 million paid to acquire the interest in WTLPG in the prior year period and $12.3 million cash paid in capital contributions to Laurel Mountain in the prior year period.

Net cash provided by (used in) financing activities for the year ended December 31, 2012 had a favorable variance compared to the prior year period mainly due to (1) $495.4 million of net proceeds received in the current period from the issuance of our new 6.625% Senior Notes; (2) $319.3 million net proceeds received in the current period from a public offering of common units, including a capital contribution from the General Partner to maintain its 2% interest; and (3) $293.9 million used in the prior year period to redeem the 8.125% Senior Notes and a portion of the 8.75% Senior Notes; partially offset by $30.8 million increased distributions paid in the current year compared to the prior year period.

Table of Contents

Capital Requirements

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. Our capital requirements consist primarily of:

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and
- expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

The following table summarizes maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Years Ended December 31,		
	2013	**2012**	**2011**
Maintenance capital expenditures	$ 21,919	$ 19,021	$ 18,247
Expansion capital expenditures	428,641	354,512	227,179
Total	$ 450,560	$ 373,533	$ 245,426

Expansion capital expenditures increased for the year ended December 31, 2013 primarily due to the completion of the Driver Plant within WestTX in April 2013 (see Recent Events) and construction costs for the Stonewall Plant within SouthOK, the Silver Oak II Plant within SouthTX, and the Edward Plant within WestTX. As of December 31, 2013, we had approved additional expenditures of approximately $358.3 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $102.5 million in purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our revolving credit facility.

Expansion capital expenditures increased for the year ended December 31, 2012 compared to the prior year period primarily due to major processing facility expansions, compressor upgrades and pipeline projects, including the construction of the V60 plant in the SouthOK system, which was placed in service in June 2012; a 200 MMCFD expansion at the WestOK system, placed in service in September 2012; and construction of the Driver Plant in the WestTX system.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash, for each calendar quarter, to our common unitholders and our General Partner 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 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.

Table of Contents

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 limited partners exceed specified targets. 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, 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 of incentive distribution rights per quarter. Incentive distributions of $15.0 million, $6.3 million and $1.7 million were paid during the years ended December 31, 2013, 2012 and 2011, respectively.

Off Balance Sheet Arrangements

As of December 31, 2013, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling $0.1 million. These are in place to support various performance obligations as required by (1) statutes within the regulatory jurisdictions where we operate, (2) surety and (3) counterparty support.

We have certain long-term unconditional purchase obligations and commitments, primarily throughput contracts. These agreements provide transportation services to be used in the ordinary course of our operations.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2013 (in thousands):

	Payments Due by Period (in thousands)				
	Total	Less than 1 Year	1 3 Years	4 5 Years	After 5 Years
Contractual cash obligations:					
Debt principal	$ 1,702,000	$	$	$ 152,000	$ 1,550,000
Interest on total debt(1)	759,897	96,317	192,634	183,127	287,819
Capital leases	754	524	230		
Operating leases	14,861	4,629	7,680	1,587	965
Total contractual cash obligations(2)	$ 2,477,512	$ 101,470	$ 200,544	$ 336,714	$ 1,838,784

(1) Based on the interest rates of our respective debt components as of December 31, 2013.

(2) Excludes non-current deferred tax liabilities of $48.2 million due to uncertainty of the timing of future cash flows for such liabilities.

	Amount of Commitment Expiration Per Period (in thousands)				
	Total	Less than 1 Year	1 3 Years	4 5 Years	After 5 Years
Other commercial commitments:					
Standby letters of credit	$ 75	$ 75	$	$	$
Purchase commitments	102,500	102,500			
Throughput contracts	25,091	9,520	7,006	6,157	2,408
Total commercial commitments	$ 127,666	$ 112,095	$ 7,006	$ 6,157	$ 2,408

Common Equity Offerings

In November 2012, we entered into an equity distribution program with Citigroup, through which we offered and sold common units for $150.0 million. Sales were made at market prices prevailing at the time of the sale. During the years ended December 31, 2013 and 2012, we issued 3,895,679 common units and 275,429 common units, respectively, under the equity distribution program for net proceeds of $137.8 million and $8.7 million, respectively, net of $2.8 million and $0.2 million, respectively, in commission paid to Citigroup, and other expenses. We also received a capital contribution from the General Partner to maintain its 2.0% general partner interest in us of $2.9 million and $0.2 million, respectively, during the years ended December 31, 2013 and 2012. The net proceeds were used for general partnership purposes. As of December 31, 2013, we had utilized the full capacity under the equity distribution program (see Item 8: Financial Statements and Supplementary Data Note 5 Common Units).

In December 2012, we sold 10,507,033 common units in a public offering at a price of $31.00 per unit, yielding net proceeds of approximately $319.3 million, including a capital contribution from the General Partner of $6.7 million to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the common unit offering to partially finance the Cardinal Acquisition (see Acquisitions).

In April 2013, we sold 11,845,000 of our common units to the public 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 TEAK Acquisition (see Item 8: Financial Statements and Supplementary Data Note 3 TEAK Midstream, LLC).

Preferred Units

In November 2012, we entered into a unit purchase agreement for a private placement of $200.0 million of newly-created Class D Preferred Units to third party investors. The unit purchase agreement was entered into to provide proceeds for the Cardinal Acquisition (see Item 8: Financial Statements and Supplementary Data Note 3 Cardinal Midstream, LLC). The agreement was terminated when we raised more than $150.0 million in common unit equity. We paid each investor a commitment fee equal to 2.0% of its commitment at the time of termination for a total expense of $4.0 million.

On May 7, 2013 we completed the 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. The Class D Preferred Units were offered and sold in a private transaction exempt from registration under

Section 4(2) of the Securities Act of 1933, as amended. 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). For the year ended December 31, 2013, we recorded costs related to preferred unit distributions of $23.6 million on our consolidated statements of operations. During the year ended December 31, 2013, we distributed 378,486 additional Class D Preferred Units to the holders of the Class D Preferred Units as a distribution in kind.

Revolving Credit Facility

At December 31, 2013, we had a $600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. We had $152.0 million outstanding borrowings as of December 31, 2013. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at December 31, 2013, was 4.0%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.1 million was outstanding at December 31, 2013. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

On April 19, 2013, we entered into an amendment to our credit agreement, which among other changes, allowed the TEAK Acquisition to be a permitted investment and did not require the joint venture interests acquired in the TEAK Acquisition to be guarantors (see Recent Events).

Borrowings under the revolving credit facility are secured by a lien on and security interest in all our property and that of our subsidiaries, except for the assets owned by the WestOK, WestTX and Centrahoma joint ventures and their respective subsidiaries. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including covenants to maintain specified financial ratios, restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are also unable to borrow under our revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

The events that constitute an event of default for our revolving credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. As of December 31, 2013, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At December 31, 2013, we had $500.0 million principal outstanding of 6.625% Senior Notes, $650.0 million principal outstanding of 5.875% Senior Notes, and $400.0 million principal outstanding of 4.75% Senior Notes (together with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes).

The Senior Notes are subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our revolving credit facility.

88

Indentures governing the Senior Notes contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all our assets. We were in compliance with these covenants as of December 31, 2013.

8.75% Senior Notes:

On January 28, 2013, we commenced a cash tender offer for any and all of our outstanding 8.75% Senior Notes and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default 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, 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 paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and $8.0 million consent payment. We 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.

6.625% Senior Notes:

On September 28, 2012, we issued $325.0 million of the 6.625% Senior Notes, at par, in a private placement transaction. We received net proceeds of $318.9 million and utilized the proceeds to reduce the outstanding balance on our revolving credit facility.

On December 20, 2012, we issued $175.0 million of the 6.625% Senior Notes in a private placement transaction. The 6.625% Senior Notes were issued at a premium of 103.0% of the principal amount for a yield of 6.0%. We received net proceeds of $176.1 million and utilized the proceeds to partially finance the Cardinal Acquisition.

The 6.625% Senior Notes are presented combined with a net $4.6 million unamortized premium as of December 31, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (see Item 8: Financial Statements and Supplementary Data Note 13 Debt). On October 16, 2013, we consummated an exchange offer for the 6.625% Senior Notes, and we incurred a 0.25% additional interest penalty of $52 thousand for the period from September 23, 2013 through consummation of the exchange offer (see Recent Events).

5.875% Senior Notes:

On February 11, 2013, we issued $650.0 million of the 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 the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the revolving credit facility. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable at any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (See Item 8: Financial Statements and Supplementary Data Note 13 Senior Notes). On January 9, 2014 we consummated an exchange offer for the 5.875% Senior Notes.

Table of Contents

4.75% Senior Notes:

On May 10, 2013, we issued $400.0 million of the 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 repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition. Interest on the 4.75% Senior Notes is payable semi-annually in arrears on May 15 and November 15. The 4.75% Senior Notes are due on November 15, 2021 and are redeemable any time after March 15, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (See Item 8: Financial Statements and Supplementary Data Note 13 Senior Notes). On January 9, 2014 we consummated an exchange offer for the 4.75% Senior Notes.

Environmental Regulation

Our operations are subject to federal, state and local laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety. We believe our operations and facilities are in substantial compliance with applicable environmental laws and regulations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, imposition of remedial requirements, issuance of injunctions affecting our operations, or other measures. Risks of accidental leaks or spills are associated with the gathering of natural gas. There can be no assurance we will not incur significant costs and liabilities relating to claims for damages to property, the environment, natural resources, or persons resulting from the operation of our business. Moreover, it is possible other developments, such as increasingly stringent environmental laws and regulations and enforcement policies, could result in increased costs and liabilities to us.

Environmental laws and regulations have changed substantially and rapidly over the last 25 years, and we anticipate there will be continuing changes. Trends in environmental regulation include increased reporting obligations and placing more restrictions and limitations on activities, such as emissions of greenhouse gases and other pollutants, generation and disposal of wastes and use, storage and handling of chemical substances, that may impact human health, the environment and/or endangered species.

Other increasingly stringent environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance we will identify and properly anticipate each such charge, or that our efforts will prevent material costs, if any, from rising.

Inflation and Changes in Prices

Inflation affects the operating expenses of our operations due to the increase in costs of labor and supplies. Inflation did not have a material impact on our results of operations for the years ended December 31, 2013, 2012 and 2011. While we anticipate inflation may affect our future operating costs, we cannot predict the timing or amounts of any such effects.

Table of Contents

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. We summarize our significant accounting policies within our consolidated financial statements included in Item 8, Financial Statements and Supplementary Data. The following table evaluates the potential impact of estimates utilized during the year ended December 31, 2013:

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Revenue Recognition Revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from gathering, processing, treating and transportation.	Revenues are estimated and accrued due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon estimated volumetric data and management estimates of the related gathering and compression fees and product prices. Costs of goods sold are estimated based upon the estimated revenues.	As of December 31, 2013, there were $134.9 million accrued unbilled revenues. A 10% change in the estimated revenues would change gross margin by approximately $2.5 million.
Impairment of Long-Lived Assets Management evaluates our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset is considered impaired when the estimated undiscounted cash flow from such asset is less than the asset s carrying value. In that event, a	In evaluating impairment, management considers the use or disposition of an asset, the estimated remaining life of an asset, and future expenditures to maintain an asset s existing service potential. In order to determine the cash flow, management must make certain estimates and	As of December 31, 2013, there were no indicators of impairment for our long-lived assets. A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an

loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset.	assumptions, which include, but are not limited to, changes in general economic conditions in regions in which we operate, our ability to negotiate favorable contracts, the risks that natural gas exploration and production activities will not occur or be successful, competition from other midstream companies, our dependence on certain significant customers and producers of natural gas, and the volume of reserves behind an asset and future NGL product and natural gas prices.	asset.

Table of Contents

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Acquisitions Purchase Price Allocation We allocate the purchase price of an acquired business to its identifiable assets and liabilities, including identifiable intangible assets, based upon estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities is recorded as goodwill. For significant acquisitions, we engage outside appraisal firms to assist in the fair value determination of identifiable intangible assets such as customer relationships and contracts. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired and liabilities assumed.	Purchase price allocation methodology requires management to make assumptions and apply judgment to estimate the fair value of acquired assets and liabilities. Management estimates the fair value of assets and liabilities primarily using a market approach, income approach, or cost approach, as appropriate. Key inputs into the fair value determinations include estimates and assumptions related to future volumes, commodity prices, operating costs, replacement costs and construction costs, as well as an estimate of the expected term and profits of the related customer contracts.	If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets and liabilities significantly differs from assumptions made during the preliminary purchase price allocation, the allocation of purchase price between goodwill, intangibles and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise.

Table of Contents

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Goodwill Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The first step of the evaluation is a qualitative analysis to determine if it is more likely than not that the carrying value of a reporting unit with goodwill exceeds its fair value. The additional quantitative steps in the goodwill impairment test are only performed if we determine that it is more likely than not that the carrying value is greater than the fair value.	Management is required to make certain assumptions when determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from acquisitions involves estimating the fair value of the reporting units and allocating the purchase price for each acquisition to each reporting unit. Goodwill is then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets. If a quantitative analysis is deemed to be required to evaluate goodwill for impairment, management determines the fair value of reporting units using the income and market approaches. These approaches are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices and production volumes. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	Management performed qualitative and/or quantitative analysis for all reporting units, except SouthTX, due to its recent acquisition. Based upon this analysis an impairment of \$43.9 million was recognized related to our Gas Treating reporting unit, which was acquired as part of the Cardinal Acquisition. Based upon the analysis of the other reporting units, it was either determined that it was more likely than not that the carrying value of the reporting unit exceeded its fair value, based on a qualitative analysis performed; or it was determined that the carrying value of the reporting units exceeded their fair value based upon a quantitative analysis performed. No further impairments were recognized (See Item 8: Financial Statements and Supplementary Data Note 7).
Depreciation and Amortization Depreciation and amortization expense is generally computed using the straight-line method over the estimated	Determination of depreciation and amortization expense requires judgment regarding the estimated	The life of our long-lived tangible assets ranges from 2 40 years, and the life of our

useful life of the assets.	useful lives. For property, plant and equipment, judgment is required to estimate salvage values. As circumstances warrant, depreciation and amortization estimates are reviewed to determine if any changes in the underlying assumptions are necessary.	definite-lived intangible assets ranges from 2 15 years. If the useful lives of our assets were decreased by 10%, we estimate that annual depreciation and amortization expense would increase by approximately $20.1 million, which would result in a corresponding change in our operating income.

Table of Contents

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Variable Interest Entities		
We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a VIE. Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the VIE s assets. When we conclude that we hold an interest in a VIE we must determine if we are the entity s primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE. We are required to consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated.	Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE. We use primarily qualitative analysis to determine if an entity is a VIE. We evaluate the entity s need for continuing financial support; the equity holder s lack of a controlling financial interest; and/or if an equity holder s voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns. We evaluate our interests in a VIE to determine whether we are the primary beneficiary. We use primarily qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE. We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions.	The T2 Joint Ventures we have equity interests in are considered to be VIEs. However, we have determined we are not the primary beneficiary of any of the T2 Joint Ventures, and thus do not consolidate these joint ventures. Changes in the design or nature of the activities of the T2 Joint Ventures, or our involvement with the T2 Joint Ventures may require us to reconsider our conclusions on the joint venture s statuses as VIEs and/or our status as not being the primary beneficiary. Such reconsideration requires significant judgment and understanding of the organization. This could result in the consolidation of the T2 Joint Ventures, which would have a significant impact on our financial statements.
Impairment of Equity Investments		
We evaluate our equity method investments in WTLPG and the T2 Joint Ventures for impairment whenever events or changes in circumstances indicate, in management s	Our impairment assessment requires us to apply judgment in estimating future cash flows from WTLPG and the T2 Joint Ventures. For WTLPG, the primary estimates are the	We determined that there were no material events or changes in circumstances that would indicate an other-than-temporary loss in

judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.

expected throughput volume to be transported and the expected transportation rates. For the T2 Joint Ventures, the primary estimate is the operating costs expected to be incurred. We determined that there were no material events or changes in circumstances that would indicate an other-than-temporary loss in value has occurred.

value has occurred. An impairment of our equity investments would have a significant impact on our financial statements.

Table of Contents

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Derivative Instruments Our derivative financial instruments are recorded at fair value in the consolidated balance sheets. Changes in fair value and settlements are reflected in our earnings in the consolidated statements of operations as gains and losses related to NGLs sales, interest expense and/or derivative loss, net. (See Item 8. Financial Statements and Supplementary Data Note 11 for further discussion)	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument s fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based upon inputs that are largely unobservable. These instruments are classified as Level 3 under the fair value hierarchy. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices. At December 31, 2013, approximately 129% of our net derivative liabilities are classified as Level 3 with the difference classified as Level 2.	If the assumptions used in the pricing models for our financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. Of the $9.1 million net derivative liabilities and the $31.0 million net derivative assets at December 31, 2013 and 2012, respectively, we had $11.8 million net derivative liabilities and $23.1 million net derivative assets, respectively, that were classified as Level 3 fair value measurements, which rely on subjective forward developed price curves. Holding all other variables constant, a 10% change in the prices utilized in calculating the Level 3 fair value of derivatives at December 31, 2013 would have resulted in approximately a $15.1 million noncash change to net income for the year ended December 31, 2013.
Income Taxes Our corporate subsidiary acquired in the Cardinal Acquisition (see Acquisitions) accounts for income taxes under the asset and liability method. (See Item 8. Financial Statements and Supplementary Data Note 9 for further discussion)	Deferred income taxes are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax	As of December 31, 2013, we have recorded deferred tax assets of $14.9 million. A 10% adjustment due to a valuation allowance related to the realization of deferred assets could result in an approximately $1.5 million

assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value.	impact on net earnings.

95

Recently Adopted Accounting Standards

See Item 8. Financial Statements and Supplementary Data Note 2 Recently Adopted Accounting Standards for information regarding recently adopted accounting pronouncements.

Recently Issued Accounting Standards

See Item 8. Financial Statements and Supplementary Data Note 2 Recently Issued Accounting Standards for information regarding recently issued accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in interest rates and oil and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All our market risk sensitive instruments were entered into for purposes other than trading.

General

All our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2013. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties to our commodity-based derivatives are banking institutions, or their affiliates, currently participating in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At December 31, 2013, we had a $600.0 million senior secured revolving credit facility with $152.0 million in outstanding borrowings. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for the revolving credit facility borrowings was 4.0% at December 31, 2013. Based upon the outstanding borrowings on the senior secured revolving credit facility and holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately $1.5 million.

96

Commodity Price Risk. 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. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. We use a number of different derivative instruments in connection with our commodity price risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, *NGLs* and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under swap agreements, we receive a fixed price and remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right to receive the difference between a fixed price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. See Item 8. Financial Statements and Supplementary Data Note 11 for further discussion of our derivative instruments. Average estimated market prices for NGLs, natural gas and condensate, based upon twelve-month forward price curves as of December 12, 2013, were $0.99 per gallon, $4.27 per million BTU 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.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Pipeline Partners, L.P. (a Delaware limited partnership) and subsidiaries (the Partnership) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership s internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 20, 2014 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 20, 2014

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,914	$ 3,398
Funds held in escrow		25,000
Accounts receivable	219,297	157,526
Current portion of derivative assets	174	23,077
Prepaid expenses and other	17,393	11,074
Total current assets	241,778	220,075
Property, plant and equipment, net	2,724,192	2,200,381
Goodwill	368,572	319,285
Intangible assets, net	696,271	199,360
Equity method investment in joint ventures	248,301	86,002
Long-term portion of derivative assets	2,270	7,942
Other assets, net	46,461	32,593
Total assets	$ 4,327,845	$ 3,065,638
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 524	$ 10,835
Accounts payable affiliates	2,912	5,500
Accounts payable	79,051	59,308
Accrued liabilities	47,449	57,752
Accrued interest payable	26,737	10,399
Current portion of derivative liabilities	11,244	
Accrued producer liabilities	152,309	109,725
Total current liabilities	320,226	253,519
Long-term portion of derivative liabilities	320	
Long-term debt, less current portion	1,706,786	1,169,083
Deferred income taxes, net	33,290	30,258
Other long-term liabilities	7,318	6,370
Commitments and contingencies		
Equity:		
Class D convertible preferred limited partners interests	450,749	
Common limited partners interests	1,703,778	1,507,676
General Partner s interest	46,118	31,501

Total partners capital	2,200,645	1,539,177
Non-controlling interest	59,260	67,231
Total equity	2,259,905	1,606,408
Total liabilities and equity	$ 4,327,845	$ 3,065,638

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2013	**2012**	**2011**
Revenue:			
Natural gas and liquids sales	$ 1,959,144	$ 1,137,261	$ 1,268,195
Transportation, processing and other fees third parties	164,874	66,287	43,464
Transportation, processing and other fees affiliates	303	435	335
Derivative gain (loss), net	(28,764)	31,940	(20,452)
Other income, net	11,292	10,097	11,192
Total revenues	2,106,849	1,246,020	1,302,734
Costs and expenses:			
Natural gas and liquids cost of sales	1,690,382	927,946	1,047,025
Plant operating	92,271	60,480	54,686
Transportation and compression	2,256	1,618	833
General and administrative	55,856	43,406	34,551
Compensation reimbursement affiliates	5,000	3,800	1,806
Other costs	20,005	15,069	1,040
Depreciation and amortization	168,617	90,029	77,435
Interest	89,637	41,760	31,603
Total costs and expenses	2,124,024	1,184,108	1,248,979
Equity income (loss) in joint ventures	(4,736)	6,323	5,025
Gain (loss) on asset sales and other	(1,519)		256,272
Goodwill impairment loss	(43,866)		
Loss on early extinguishment of debt	(26,601)		(19,574)
Income (loss) from continuing operations before tax	(93,897)	68,235	295,478
Income tax expense (benefit)	(2,260)	176	
Income (loss) from continuing operations	(91,637)	68,059	295,478
Discontinued operations:			
Loss on sale of discontinued operations			(81)
Loss from discontinued operations net of tax			(81)
Net Income (loss)	(91,637)	68,059	295,397
Income attributable to non-controlling interests	(6,975)	(6,010)	(6,200)

Preferred unit imputed dividend effect	(29,485)		
Preferred unit dividends in kind	(23,583)		
Preferred unit dividends			(389)
Net income (loss) attributable to common limited partners and the General Partner	$ (151,680)	$ 62,049	$ 288,808

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (continued)

(in thousands, except per unit data)

	Years Ended December 31,		
	2013	**2012**	**2011**
Allocation of net income (loss) attributable to:			
Common limited partner interest:			
Continuing operations	$ (165,923)	$ 52,391	$ 281,449
Discontinued operations			(79)
	(165,923)	52,391	281,370
General Partner interest:			
Continuing operations	14,243	9,658	7,440
Discontinued operations			(2)
	14,243	9,658	7,438
Net income (loss) attributable to:			
Continuing operations	(151,680)	62,049	288,889
Discontinued operations			(81)
	$ (151,680)	$ 62,049	$ 288,808
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ (2.23)	$ 0.95	$ 5.22
Discontinued operations			
	$ (2.23)	$ 0.95	$ 5.22
Weighted average common limited partner units (basic)	74,364	54,326	53,525
Diluted:			
Continuing operations	$ (2.23)	$ 0.95	$ 5.22
Discontinued operations			
	$ (2.23)	$ 0.95	$ 5.22
Weighted average common limited partner units (diluted)	74,364	55,138	53,944

See accompanying notes to consolidated financial statements

101

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Years Ended December 31, 2013	2012	2011
Net income (loss)	$ (91,637)	$ 68,059	$ 295,397
Other comprehensive income:			
Adjustment for realized losses on cash flow hedges reclassified to net income (loss)		4,390	6,834
Total other comprehensive income		4,390	6,834
Comprehensive income (loss)	$ (91,637)	$ 72,449	$ 302,231
Comprehensive income attributable to non-controlling interests	$ 6,975	$ 6,010	$ 6,200
Preferred unit imputed dividend effect	29,485		
Preferred unit dividends in kind	23,583		
Preferred unit dividends			389
Comprehensive income (loss) attributable to common limited partners and the General Partner	(151,680)	66,439	295,642
Comprehensive income (loss)	$ (91,637)	$ 72,449	$ 302,231

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

	Number of Limited Partner Units		Preferred Limited Partners	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
	Preferred	Common						
Balance at January 1, 2011	8,000	53,338,010	$ 8,000	$ 1,057,342	$ 20,066	$ (11,224)	$ (32,537)	$ 1,041,647
Redemption of preferred limited partner units	(8,000)		(8,000)					(8,000)
Issuance of common units under incentive plans		308,051		468				468
Purchase and retirement of common limited partner units		(28,878)		(984)				(984)
Unissued common units under incentive plans				3,003				3,003
Distributions paid			(629)	(96,036)	(3,648)			(100,313)
Distributions payable			240					240
Distributions to non-controlling interests							(2,064)	(2,064)
Other comprehensive income						6,834		6,834
Net income			389	281,370	7,438		6,200	295,397
Balance at December 31, 2011		53,617,183	$	$ 1,245,163	$ 23,856	$ (4,390)	$ (28,401)	$ 1,236,228
Issuance of units and		10,782,462		321,491	6,865			328,356

General Partner capital contribution								
Issuance of common units under incentive plans		180,417		128				128
Purchase and retirement of common limited partner units		(24,052)		(695)				(695)
Unissued common units under incentive plans				11,421				11,421
Distributions paid				(122,223)	(8,878)			(131,101)
Contributions from non-controlling interests							182	182
Other comprehensive income						4,390		4,390
Increase in non-controlling interest related to business combination							89,440	89,440
Net income				52,391	9,658		6,010	68,059
Balance at December 31, 2012		64,556,010	$	$ 1,507,676	$ 31,501	$	$ 67,231	$ 1,606,408
Issuance of units and General Partner capital contribution	13,445,383	15,740,679	397,681	526,263	19,359			943,303
Issuance of common units under incentive plans		288,459		159				159
Unissued common units under incentive plans				18,984				18,984
Distributions paid in kind units	378,486							

Distributions paid				(183,381)	(18,985)			(202,366)
Contributions from non-controlling interests							17,021	17,021
Distributions to non-controlling interests							(1,432)	(1,432)
Decrease in non-controlling interest related to business combination							(30,535)	(30,535)
Net income (loss)			53,068	(165,923)	14,243		6,975	(91,637)
Balance at December 31, 2013	13,823,869	80,585,148	$ 450,749	$ 1,703,778	$ 46,118	$	$ 59,260	$ 2,259,905

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (91,637)	$ 68,059	$ 295,397
Less: Loss from discontinued operations net of tax			(81)
Income (loss) from continuing operations	(91,637)	68,059	295,478
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	168,617	90,029	77,435
Loss on goodwill impairment	43,866		
Equity (income) loss in joint ventures	4,736	(6,323)	(5,025)
Distributions received from equity method joint ventures	7,400	7,200	4,448
Non-cash compensation expense	19,344	11,635	3,274
Amortization of deferred finance costs	6,965	4,672	4,480
Loss on early extinguishment of debt	26,601		19,574
Loss (gain) on asset disposition	1,519		(256,272)
Deferred income tax expense (benefit)	(2,260)	176	
Change in operating assets and liabilities, net of business combinations:			
Accounts receivable, prepaid expenses and other	(73,307)	(31,417)	(16,216)
Accounts payable and accrued liabilities	61,449	37,952	5,093
Accounts payable and accounts receivable affiliates	(2,588)	2,825	(9,605)
Derivative accounts payable and receivable	40,139	(10,170)	(19,797)
Net cash provided by operating activities	210,844	174,638	102,867
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(450,560)	(373,533)	(245,426)
Cash paid for business combinations, net of cash received	(975,887)	(633,610)	(85,000)
Proceeds from preferred rights to note receivable			8,500
Investment in joint ventures	(13,366)		(12,250)
Net proceeds related to asset sales			403,578
Other	(3,270)	502	(1,558)
Net cash provided by (used in) continuing investing activities	(1,443,083)	(1,006,641)	67,844
Net cash provided by (used in) discontinued investing activities			(81)
Net cash provided by (used in) investing activities	$ (1,443,083)	$ (1,006,641)	$ 67,763

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

(in thousands)

	Years Ended December 31, 2013	2012	2011
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	$ 1,267,000	$ 1,170,500	$ 1,515,500
Repayments under credit facility	(1,408,000)	(1,019,500)	(1,443,500)
Net proceeds from issuance of long term debt	1,028,092	495,374	152,366
Repayment of long-term debt	(365,822)		(279,557)
Payment of premium on retirement of debt	(25,581)		(14,342)
Payment of deferred financing costs	(929)	(4,542)	
Payment for acquisition-based contingent consideration	(6,000)		
Principal payments on capital lease	(10,750)	(2,523)	(954)
Net proceeds from issuance of common and preferred limited partner units	923,944	321,491	468
Purchase and retirement of treasury units		(695)	(984)
Redemption of preferred limited partner units			(8,000)
General Partner capital contributions	19,359	6,865	
Contributions from non-controlling interest holders	17,021	182	
Distributions to non-controlling interest holders	(1,432)		(2,064)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(202,366)	(131,101)	(100,313)
Other	(781)	(818)	10,754
Net cash provided by financing activities	1,233,755	835,233	(170,626)
Net change in cash and cash equivalents	1,516	3,230	4
Cash and cash equivalents, beginning of period	3,398	168	164
Cash and cash equivalents, end of period	$ 4,914	$ 3,398	$ 168

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States; natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and the transportation of NGLs in the southwestern region of the United States. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. At December 31, 2013, Atlas Pipeline Partners GP, LLC (the General Partner) owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. (ATLS), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At December 31, 2013, the Partnership had 80,585,148 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; and 13,823,869 Class D convertible preferred units (Class D Preferred Units) outstanding (see Note 5).

The Partnership has revised the presentation of its consolidated statements of comprehensive income (loss) in order to more clearly distinguish the amounts of other comprehensive income (loss) attributable to each of the common unitholders, preferred unitholders, and the non-controlling interest. This change in presentation has been applied to all periods presented. The previously reported amounts of other comprehensive income (loss) attributable to the common limited partners and the General Partner did not change for any period.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership s wholly-owned and majority-owned subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 2.0% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The Partnership s consolidated financial statements include its 95% interest in joint ventures, which individually own a 100% interest in the WestOK natural gas gathering system and processing plants and a 72.8% undivided interest in the WestTX natural gas gathering system and processing plants. These joint ventures have a $1.9 billion note receivable from the holder of the non-controlling interest in the joint ventures, which is reflected within non-controlling interests on the Partnership s consolidated balance sheets.

The Partnership s consolidated financial statements also include its 60% interest in Centrahoma Processing LLC (Centrahoma). The remaining 40% ownership interest is held by MarkWest Oklahoma Gas Company LLC (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE).

The Partnership consolidates 100% of these joint ventures and reflects the non-controlling interest in the joint ventures on its statements of operations. The Partnership also reflects the non-controlling interest in the net assets of the joint venture as a component of equity on its consolidated balance sheets.

The WestTX joint venture has a 72.8% undivided joint interest in the WestTX system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) (Pioneer). Due to the ownership of the WestTX system being in the form of an undivided interest, the WestTX joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the WestTX system.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as other comprehensive income (loss) and for the Partnership only include changes in the fair value of unsettled derivative contracts, which were previously accounted for as cash flow hedges (see Note 10). These contracts are wholly-owned by the Partnership and the related gains and losses are not shared with the non-controlling interests. The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss). During the years ended December 31, 2012 and 2011, the Partnership reclassified $4.4 million and $6.8 million, respectively, from other comprehensive income to natural gas and liquids sales within the Partnership s consolidated statements of operations. As of December 31, 2013 and 2012, all amounts had been reclassified out of accumulated other comprehensive income and the Partnership had no amounts outstanding within accumulated other comprehensive income.

Equity Method Investments

The Partnership s consolidated financial statements include its previously owned 49% non-controlling interest in Laurel Mountain Midstream, LLC joint venture (Laurel Mountain) until it was sold in February 2011; its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG); and its interests in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle), T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford), and T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen) (the T2 Joint Ventures), which were acquired as part of the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) for $974.7 million in cash, including final purchase price adjustments, less cash received (the TEAK Acquisition) (see Notes 3 and 4). The Partnership accounts for its investments in these joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures net income (loss) as equity income on its consolidated statements of operations. Investments in excess of the underlying net assets of equity method investees identifiable to property, plant and equipment or finite lived intangible assets are amortized over the useful life of the related assets and recorded as a reduction to equity investment on the Partnership s consolidated balance sheet with an offsetting reduction to equity income on the Partnership s consolidated statements of operations. Excess investment representing equity method goodwill is not subject to amortization and is accounted for as a component of the investment. No goodwill was recorded on the acquisition of Laurel Mountain, WTLPG, or the T2 Joint Ventures. Equity method investments are subject to impairment evaluation. The Partnership noted no indicators of impairment for its equity method investments as of December 31, 2013 or 2012.

Use of Estimates

The preparation of the Partnership s consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership s consolidated financial

statements, as well as the reported amounts of revenue and expense during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depreciation and amortization, asset impairment, the fair value of derivative instruments, the probability of forecasted transactions, the allocation of purchase price to the fair value of assets acquired and other items. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management of the Partnership believes the operating results presented represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments. Checks outstanding at the end of a period that exceed available cash balances held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At December 31, 2013 and 2012, the Partnership reclassified the balance related to book overdrafts of $28.8 million and $27.6 million, respectively, from cash and cash equivalents to accounts payable on the Partnership s consolidated balance sheets.

Receivables

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its customers. At December 31, 2013 and 2012, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

NGL Linefill

The Partnership had $14.5 million and $7.8 million of NGL linefill at December 31, 2013 and 2012, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties for which the counterparty will pay at a designated later period at a price determined by the then current market price (see Note 11).

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two or more years through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful life of an asset for two or more years through the replacement of critical components are capitalized. The Partnership capitalizes interest on borrowed funds related to capital projects for periods during which activities are in progress to bring these projects to their intended use. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be

108

the major asset classes of its gathering, processing and treating systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering, processing and treating components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership s results of operations.

Leased property and equipment meeting capital lease criteria are capitalized based on the minimum payments required under the lease and are included within property, plant and equipment on the Partnership s consolidated balance sheets (see Note 6). Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership s consolidated balance sheets (see Note 13). Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or circumstances indicate the carrying amount of an asset may not be recoverable. If it is determined an asset s estimated future undiscounted cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value, if such carrying amount exceeds the fair value. The fair value measurement of a long-lived asset is based on inputs that are not observable in the market and therefore represent Level 3 inputs (see Fair Value of Financial Instruments). No impairment charges were recognized for the years ended December 31, 2013, 2012 and 2011.

Asset Retirement Obligation

The Partnership performs ongoing analysis of asset removal and site restoration costs that the Partnership may be required to perform under law or contract once an asset has been permanently taken out of service. The Partnership has property, plant and equipment at locations owned by the Partnership and at sites leased or under right of way agreements. The Partnership is under no contractual obligation to remove the assets at locations it owns. In evaluating its asset retirement obligation, the Partnership reviews its lease agreements, right of way agreements, easements and permits to determine which agreements, if any, require an asset removal and restoration obligation. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted-risk-free interest rates. However, the Partnership was not able to reasonably measure the fair value of the asset retirement obligation as of December 31, 2013 or 2012 because the settlement dates were indeterminable. Any cost incurred in the future to remove assets and restore sites will be expensed as incurred.

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. Impairment testing for goodwill is done at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available, and segment management regularly reviews the operating results of that component. The Partnership evaluates goodwill for impairment annually, on December 31 for all reporting units, except SouthTX, which will be evaluated on April 30. The Partnership also evaluates goodwill for impairment whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is

109

less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. If a two-step process goodwill impairment test is required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

The Partnership completed a qualitative test for goodwill for its WestOK reporting unit and determined there were no substantive changes during the current year and no indication of impairment. The Partnership completed the first step of the goodwill impairment test for its SouthOK reporting unit and determined the reporting unit exceeded its carrying amount and, therefore, the second step of the two-step goodwill impairment test was unnecessary. The Partnership completed the two step goodwill impairment test for the Gas Treating reporting unit and determined the goodwill was impaired and recorded a goodwill impairment loss of $43.9 million (see Note 7). The Partnership performed a review for triggering events for the goodwill recorded on the SouthTX reporting unit and noted there were no substantive changes. A full impairment evaluation of the goodwill recorded on the SouthTX reporting unit will be performed once final purchase price adjustments have been made and the measurement period is completed. No goodwill impairments charges were recognized for the years ended December 31, 2012 and 2011 (see Note 7).

Intangible Assets

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis, on December 31, to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management s estimate of whether these individual relationships will continue in excess or less than the average length (see Note 7).

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates. The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty, measured at fair value (see Fair Value of Financial Instruments). Changes in a derivative instrument s fair value are recognized currently in the consolidated statements of operations. The Partnership no longer applies hedge accounting for its derivatives. As such, changes in fair value of these derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. Prior to discontinuance of hedge accounting, the change in the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive loss within equity on the Partnership s consolidated balance sheets. Amounts in accumulated other comprehensive loss were reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affected earnings. The Partnership has reclassified all earnings out of accumulated other comprehensive loss, within equity on the Partnership s consolidated balance sheets and had no amounts in accumulated other comprehensive loss as of December 31, 2013 and 2012.

110

Table of Contents

Fair Value of Financial Instruments

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership s own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity s own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 11). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership has a financial risk management committee (the Financial Risk Management Committee), which sets the policies, procedures and valuation methods utilized by the Partnership to value its derivative contracts. The Financial Risk Management Committee members include, among others, the Chief Executive Officer, the Chief Financial Officer and the Vice Chairman of the managing board of the General Partner. The Financial Risk Management Committee receives daily reports and meets on a weekly basis to review the risk management portfolio and changes in the fair value in order to determine appropriate actions.

Income Taxes

The Partnership is generally not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership s taxable income. Such taxable income may vary substantially from net income (loss) reported in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership s tax returns and disallows the recognition of tax positions not deemed to meet a more-likely-than-not threshold of being sustained by the applicable tax authority. The Partnership s management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership s policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements as of December 31, 2013 or 2012.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2013 except for: 1) an ongoing examination by the Texas Comptroller of Public Accounts related to the Partnership s Texas Franchise Tax for franchise report years 2008 through 2011 and 2) an examination by the Internal Revenue Service related to the Partnership s corporate subsidiary APL Arkoma, Inc. s Federal Corporate Return for the period ended December 31, 2012.

Table of Contents

APL Arkoma, Inc. is subject to federal and state income tax. The Partnership s corporate subsidiary accounts for income taxes under the asset and liability method. Deferred income taxes are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value. The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level. See Note 9 for discussion of the Partnership s federal and state income tax expense (benefits) of its taxable subsidiary as well as the Partnership s net deferred income tax assets (liabilities).

Share-Based Compensation

All share-based payments to employees, including grants of employee stock options, are recognized in the financial statements based on their fair values. Share-based awards, which have a cash option, are classified as liabilities on the Partnership s consolidated balance sheets. All other share-based awards are classified as equity on the Partnership s consolidated balance sheets. Compensation expense associated with share-based payments is recognized within general and administrative expenses on the Partnership s statements of operations from the date of the grant through the date of vesting, amortized on a straight-line method. Generally, no expense is recorded for awards that do not vest due to forfeiture.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholders interests. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner s and limited partners ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution. However, the contractual terms of the Class D Preferred Units do not require the holders to share in the losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 16), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award s vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. Therefore, the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income (loss) from continuing operations and net income from discontinued operations allocated to the General Partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands):

Table of Contents

	Years Ended December 31, 2013	2012	2011
Continuing operations:			
Net income (loss)	$ (91,637)	$ 68,059	$ 295,478
Income attributable to non-controlling interests	(6,975)	(6,010)	(6,200)
Preferred unit imputed dividend effect	(29,485)		
Preferred unit dividends in kind	(23,583)		
Preferred unit dividends			(389)
Net income (loss) attributable to common limited partners and the General Partner	(151,680)	62,049	288,889
General Partner s cash incentive distributions	17,646	8,583	1,666
General Partner s ownership interest	(3,403)	1,075	5,774
Net income attributable to the General Partner s ownership interests	14,243	9,658	7,440
Net income (loss) attributable to common limited partners	(165,923)	52,391	281,449
Net income attributable to participating securities phantom units(1)		772	2,187
Net income attributable to participating securities Class D Preferred Units(2)			
Net income attributable to participating securities		772	2,187
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ (165,923)	$ 51,619	$ 279,262
Discontinued operations:			
Net loss	$	$	$ (81)
Net loss attributable to the General Partner s ownership interests			(2)
Net loss utilized in the calculation of net income (loss) from discontinued operations attributable to common limited partners per unit	$	$	$ (79)

(1) Net income attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). Net loss attributable to common limited partners ownership interest is not allocated to approximately 1,240,000 weighted average phantom units for the year ended December 31, 2013 because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the

entity.

(2) Net income attributable to common limited partners ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average Class D Preferred Units outstanding as a percentage of the sum of the weighted average Class D Preferred Units and common limited partner units outstanding). For the year ended December 31, 2013, net loss attributable to common limited partners ownership interest is not allocated to approximately 9,110,000 weighted average Class D Preferred Units because the contractual terms of the Class D Preferred Units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities.

Table of Contents

The following table sets forth the reconciliation of the Partnership s weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Weighted average number of common limited partner units basic	74,364	54,326	53,525
Add effect of dilutive securities phantom units[1]		812	419
Add effect of convertible preferred limited partner units[2]			
Weighted average common limited partner units diluted	74,364	55,138	53,944

(1) For the year ended December 31, 2013, approximately 1,240,000 weighted average phantom units 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.

(2) For the year ended December 31, 2013, approximately 9,110,000 weighted average Class D Preferred Units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

Environmental Matters

The Partnership is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Partnership has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures, including legislation related to greenhouse gas emissions. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. At this time, the Partnership is unable to assess the timing and/or effect of potential liabilities related to greenhouse gas emissions or other environmental issues. The Partnership maintains insurance, which may cover, in whole or in part, certain environmental expenditures. At December 31, 2013 and 2012, the Partnership had no material environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating). These reportable segments reflect the way the Partnership manages its operations.

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 Anadarko, Arkoma, Eagle Ford and Permian Basins; (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee; and (3) through year ending December 31, 2011, the revenues and gain on sale related to the Partnership s former 49% interest in Laurel Mountain (see Note 4). Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of the Gas Treating operations located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; and the Partnership s 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Contract gas treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering, processing, treating and transportation operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced NGLs, if any, off delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas and NGLs is recognized upon physical delivery. In connection with the Partnership s gathering, processing and transportation operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas and for transporting NGLs. Revenue is a function of the volume of natural gas that the Partnership gathers and processes or the volume of NGLs transported and is not directly dependent on the value of the natural gas or NGLs. However, sustained low commodity prices could result in a decline in drilling activities by producers with consequently a decline in volumes, and a corresponding decrease in fee revenue. The Partnership is also paid a separate compression fee on many of its gathering systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP contracts may include a fee component, which is charged to the producer.

Fixed Recoveries. Fee-based or POP contracts sometimes include fixed recovery terms, which mean the prices paid or products returned to the producer are calculated using an agreed NGL recovery factor, regardless of the volumes of NGLs actually recovered through processing.

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates per MMBTU. The volume and energy content of gas gathered or purchased is based on the measurement at an agreed upon location (generally at the wellhead). The BTU quantity of gas redelivered or sold at the tailgate of the Partnership s processing facility may be lower than the BTU quantity purchased at the wellhead primarily due to the NGLs extracted from the natural gas when processed through a plant. The Partnership must make up or keep the producer whole for this loss in BTU quantity. To offset the make-up obligation, the Partnership retains the NGLs, which are extracted, and sells them for its own account. Therefore, the Partnership bears the economic risk (the processing margin risk) that (1) the BTU quantity of residue gas available for redelivery to the producer may be less than received from the producer; and/or (2) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements are lower in BTU content and thus can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods when the processing margin risk is uneconomic.

The Partnership accrues unbilled revenue and the related purchase costs due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership s records and management estimates of the related gathering and compression fees, which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at December 31, 2013 and 2012 of $134.9 million and $100.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Accrued Producer Liabilities

Accrued producer liabilities on the Partnership s consolidated balance sheets represent accrued purchase commitments payable to producers related to gas gathered and processed through its system under its POP and Keep-Whole contracts (see Revenue Recognition).

Recently Adopted Accounting Standards

In February 2013, the FASB issued Accounting Standards Update (ASU) 2013-02, Other Comprehensive Income (Topic 220) Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, which, among other changes, requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component and the respective line items of net income to which the amounts were reclassified. The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2012. The Partnership began including the additional required disclosures upon the adoption of this ASU on January 1, 2013 (see Comprehensive Income (Loss)). The adoption had no material impact on the Partnership s financial position or results of operations.

Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership applied these requirements upon the adoption of the ASU on January 1, 2014. The adoption had no material impact on the Partnership s financial position or results of operations.

Table of Contents

NOTE 3   ACQUISITIONS

Cardinal Midstream, LLC

On December 20, 2012, the Partnership completed the acquisition of 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $598.9 million in cash, including final purchase price adjustments, less cash received (the   Cardinal Acquisition). The assets of these companies, which are referred to as the Arkoma assets, include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas. The acquisition includes a 60% interest in Centrahoma Processing, LLC (Centrahoma). The remaining 40% ownership interest in Centrahoma is held by MarkWest Oklahoma Gas Company LLC (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE). As part of the Cardinal Acquisition, the Partnership placed $25.0 million into escrow to cover potential indemnity claims. The $25.0 million was released to the sellers in June 2013.

The Partnership funded the purchase price for the Cardinal Acquisition in part from the private placement of $175.0 million of its 6.625% senior unsecured notes due October 1, 2020 (6.625% Senior Notes) at a premium of 3.0%, for net proceeds of $176.1 million (see Note 13); and from the sale of 10,507,033 common limited partner units in a public offering at a negotiated purchase price of $31.00 per unit, generating net proceeds of approximately $319.3 million, including the General Partner s contribution of $6.7 million to maintain its 2.0% general partner interest in the Partnership (see Note 5). The Partnership funded the remaining purchase price from its senior secured revolving credit facility (see Note 13).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. The following table presents the values assigned to the assets acquired and liabilities assumed in the Cardinal Acquisition, based on their final estimated fair values as of the date of acquisition, including the 40% non-controlling interest of Centrahoma held by MarkWest (in thousands):

Cash	$ 1,184
Accounts receivable	13,783
Prepaid expenses and other	1,289
Property, plant and equipment	246,787
Intangible assets	232,740
Goodwill	214,090
Total assets acquired	709,873
Current portion of long-term debt	(341)
Accounts payable and accrued liabilities	(14,596)
Deferred tax liability, net	(35,353)
Long-term debt, less current portion	(604)
Total liabilities acquired	(50,894)
Non-controlling interest	(58,905)

Net assets acquired	**600,074**
Less cash received	(1,184)
Net cash paid for acquisition	**$ 598,890**

The fair value of MarkWest s 40% non-controlling interest in Centrahoma was based upon the purchase price allocated to the 60% controlling interest the Partnership acquired using an income approach. This measurement uses significant inputs that are not observable in the market and thus represents a fair value measurement categorized within Level 3 of the fair value hierarchy. The 40% non-controlling interest in Centrahoma was reduced by a 5.0% adjustment for lack of control that market participants would consider when measuring its fair value.

Subsequent to recording the final estimated fair values of the assets acquired and liabilities assumed in the Cardinal Acquisition, the Partnership determined that a portion of goodwill recorded in connection with the acquisition was impaired (see Note 7).

TEAK Midstream, LLC

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) for $974.7 million in cash, including final purchase price adjustments, less cash received (the TEAK Acquisition), including $50.0 million placed into escrow to cover potential indemnity claims. The $50.0 million in escrow was released during the three months ended December 31, 2013. The assets of these companies, which are referred to as the SouthTX assets, include the following gas gathering and processing facilities in 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, which owns a 62 mile, 24-inch gathering line;
- a 50% interest in 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 Co-Gen, which owns a cogeneration facility.

As a result of the TEAK Acquisition, the Partnership has added additional gathering and processing capacity as well as fee-based cash flows from natural gas gathering and processing operations.

The Partnership funded the purchase price for the TEAK Acquisition in part from the private placement of $400.0 million of Class D Preferred Units for net proceeds of $397.7 million, plus the General Partner s contribution of $8.2 million to maintain its 2.0% general partner interest in the Partnership (see Note 5); and in part from the sale of 11,845,000 common limited partner units in a public offering for net proceeds of approximately $388.4 million, plus the General Partner s contribution of $8.3 million to maintain its 2.0% general partner interest in the Partnership (see Note 5). The Partnership funded the remaining purchase price from its senior secured revolving credit facility, and issued $400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes) on May 10, 2013 for net proceeds of $391.2 million to reduce the level of borrowings under the revolving credit facility as part of the TEAK Acquisition (see Note 13).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. Due to the recent date of acquisition, the accounting for the business combination is based on preliminary data that remains subject to adjustment and could change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date and the changes could be material.

Table of Contents

The following table presents the values assigned to the assets acquired and liabilities assumed in the TEAK Acquisition, based on their preliminary estimated fair values at the date of the acquisition (in thousands):

Cash	$	8,074
Accounts receivable		11,055
Prepaid expenses and other		1,626
Property, plant and equipment		198,752
Intangible assets		450,000
Goodwill		188,859
Equity method investment in joint ventures		161,069
Total assets acquired		1,019,435
Accounts payable and accrued liabilities		(36,690)
Total liabilities acquired		(36,690)
Net assets acquired		**982,745**
Less cash received		(8,074)
Net cash paid for acquisition	**$**	**974,671**

In conjunction with the issuance of the Partnership s common limited partner units associated with the acquisition, $14.3 million of transaction fees were included in the $388.4 million net proceeds recorded within common limited partners interests on the Partnership s consolidated balance sheets. In conjunction with the issuance of the Partnership s Class D Preferred Units associated with the acquisition, $2.3 million of transaction fees were included in the $397.7 million proceeds recorded within preferred limited partner interests on the Partnership s consolidated balance sheets. In conjunction with the issuance of the 4.75% Senior Notes and an amendment of the revolving credit facility, $9.7 million of transaction fees were recorded as deferred finance costs within other assets, net on the Partnership s consolidated balance sheets. Other acquisition costs of $19.3 million associated with the TEAK Acquisition were expensed as incurred and recorded to other costs on the Partnership s consolidated statements of operations.

Revenues and net losses of $97.4 million and $14.6 million for the year ended December 31, 2013, respectively, from the acquisition date of May 7, 2013 have been included in the Partnership s consolidated financial statements related to the TEAK Acquisition, which were included in the Partnership s Gathering and Processing reportable segment. Net earnings of $1.1 million contributed from the TEAK Acquisition from April 1, 2013 (the effective date) to May 7, 2013 (the closing date) were included as a reduction to the purchase price.

The following table provides the unaudited pro forma revenue, net income, and net income per basic and diluted common unit for the years ended December 31, 2013 and 2012 as if the following had been included in operations commencing on January 1, 2012: (A)(1) the TEAK Acquisition; (2) the common unit equity offering for net proceeds of $388.4 million in April 2013; (3) the Class D Preferred Unit offering for net proceeds of $397.7 million in April 2013; (4) the General Partner s contribution of $16.5 million to maintain its 2.0% general partner interest in the Partnership; and (5) the issuance of $400.0 million of 4.75% Senior Notes for net proceeds of $391.2 million; and (B) (1) the Cardinal Acquisition; (2) the common unit equity offering for net proceeds of $319.3 million in December 2012, including General Partner contribution; (3) the $176.1 million net proceeds from the 6.625% Senior Notes; and

(4) the borrowings under the Partnership s revolving credit facility (in thousands, except per unit data; unaudited):

120

	Years Ended December 31, 2013	Years Ended December 31, 2012
Total revenues	$ 2,142,962	$ 1,539,044
Continuing net loss after tax attributable to common limited partners and the General Partner (1)	(184,973)	(97,301)
Continuing net loss after tax attributable to common limited partner unit:		
Basic and diluted (1)	$ (2.56)	$ (1.38)

(1) Pro forma earnings for the year ended December 31, 2013 were adjusted to exclude $19.3 million of TEAK Acquisition related costs incurred and pro forma earnings for the year ended December 31, 2012 were adjusted to include these costs.

The Partnership has prepared these unaudited pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed the TEAK and Cardinal Acquisitions and financing transactions at the beginning of the periods shown above or the results that will be attained in the future.

NOTE 4 EQUITY METHOD INVESTMENTS

Laurel Mountain

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources, LLC (Atlas Energy Resources), a wholly-owned subsidiary of Atlas Energy, Inc (AEI) (the Laurel Mountain Sale) for $409.5 million in cash, net of expenses and adjustments based on capital contributions made to and distributions received from Laurel Mountain after January 1, 2011. Concurrently, AEI became a wholly-owned subsidiary of Chevron Corporation (the Chevron Merger) and divested its interests in ATLS, resulting in the Laurel Mountain Sale being classified as a third party sale. The Partnership recognized on its consolidated statements of operations a net gain on the sale of assets of $256.3 million during the year ended December 31, 2011. Laurel Mountain is a joint venture, which owns and operates the Appalachia natural gas gathering system previously owned by the Partnership. Subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) hold the remaining 51% ownership interest. The Partnership utilized the proceeds from the sale to repay its indebtedness and for general company purposes.

The Partnership accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income on its consolidated statements of operations. Since the Partnership accounted for its ownership as an equity investment, the Partnership did not reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

The Partnership retained its preferred distribution rights with respect to an $8.5 million balance due on a note receivable from Williams. In December 2011, Williams made cash payment to the Partnership to settle the balance on the note receivable, plus accrued interest of $0.2 million.

West Texas LPG Pipeline Limited Partnership

On May 11, 2011, the Partnership acquired a 20% interest in WTLPG from Buckeye Partners, L.P. (NYSE: BPL) for $85.0 million. WTLPG owns a 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. At the acquisition date, the carrying value of the 20% interest in WTLPG exceeded the Partnership s share of the underlying net assets of WTLPG by approximately $49.9 million. The Partnership s analysis of this difference determined that it related to the fair value of property plant and equipment, which was in excess of book value. This excess will be depreciated over approximately 38 years. The Partnership recognizes its 20% interest in WTLPG as an investment in joint ventures on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income in joint ventures on its consolidated statements of operations. The Partnership incurred costs of $0.6 million during the year ended December 31, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership s consolidated statements of operations.

T2 Joint Ventures

On May 7, 2013, the Partnership acquired a 75% interest in T2 LaSalle, a 50% interest in T2 Eagle Ford and a 50% interest in T2 EF Co-Gen as part of the TEAK Acquisition (see Note 3). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity (VIE), but the Partnership does not meet the qualifications as the primary beneficiary. Even though the Partnership owns a 50% or greater interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. The Partnership shares equal management rights with TexStar Midstream Services, L.P. (TexStar), the investor owning the remaining interests; and TexStar is the operator of the T2 Joint Ventures. The Partnership determined that it should account for the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The Partnership s maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment; any additional capital contribution commitments and the Partnership s share of any approved operating expenses incurred by the VIEs.

The following table presents the value of the Partnership s equity method investments in joint ventures as of December 31, 2013 and December 31, 2012 (in thousands):

	December 31, 2013	December 31, 2012
WTLPG	$ 85,790	$ 86,002
T2 LaSalle	50,534	
T2 Eagle Ford	97,437	
T2 EF Co-Gen	14,540	
Equity method investment in joint ventures	$ 248,301	$ 86,002

Table of Contents

The following table presents the Partnership s equity income (loss) in joint ventures for each of the three years ended December 31, 2013 (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Laurel Mountain	$	$	$ 462
WTLPG	4,988	6,323	4,563
T2 LaSalle	(3,127)		
T2 Eagle Ford	(4,408)		
T2 EF Co-Gen	(2,189)		
Equity income (loss) in joint ventures	$ (4,736)	$ 6,323	$ 5,025

NOTE 5 EQUITY

Common Units

In November 2012, the Partnership entered into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership offered and sold through Citigroup, as its sales agent, common units for $150.0 million. Sales were at market prices prevailing at the time of the sale. During the years ended December 31, 2013 and 2012, the Partnership issued 3,895,679 and 275,429 common units, respectively, under the equity distribution program for net proceeds of $137.8 million and $8.7 million, respectively, net of $2.8 million and $0.2 million, respectively, in commissions incurred from Citigroup, and other expenses. The Partnership also received capital contributions from the General Partner of $2.9 million and $0.2 million during the years ended December 31, 2013 and 2012, respectively, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offering were utilized for general partnership purposes. As of December 31, 2013, the Partnership had used the full capacity under the equity distribution program.

In December 2012, the Partnership sold 10,507,033 common units in a public offering at a price of $31.00 per unit, yielding net proceeds of approximately $319.3 million, including $6.7 million contributed by the General Partner to maintain its 2.0% general partner interest. The Partnership utilized the net proceeds from the common unit offering to partially finance the Cardinal Acquisition (see Note 3).

In April 2013, the Partnership sold 11,845,000 common units in a public offering at a price of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. The Partnership also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest. The Partnership used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition (see Note 3).

Cash Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership s securities with the right to share in the Partnership s cash distributions) and to the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels, including the General Partner s

2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial $7.0 million per quarter of incentive distribution rights.

Common unit and General Partner distributions declared by the Partnership for quarters ending from December 31, 2010 through September 30, 2013 were as follows:

For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
December 31, 2010	February 14, 2011	$ 0.37	$ 19,735	$ 398
March 31, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967
September 30, 2011	November 14, 2011	0.54	28,953	1,844
December 31, 2011	February 14, 2012	0.55	29,489	2,031
March 31, 2012	May 15, 2012	0.56	30,030	2,217
June 30, 2012	August 14, 2012	0.56	30,085	2,221
September 30, 2012	November 14, 2012	0.57	30,641	2,409
December 31, 2012	February 14, 2013	0.58	37,442	3,117
March 31, 2013	May 15, 2013	0.59	45,382	3,980
June 30, 2013	August 14, 2013	0.62	48,165	5,875
September 30, 2013	November 14, 2013	0.62	49,298	6,013

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its 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.

Class C Preferred Units

On February 17, 2011, as part of the Chevron Merger (see Note 4), Chevron acquired 8,000 cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units), which were previously owned by AEI. On May 27, 2011, the Partnership redeemed the Class C Preferred Units for cash at the liquidation value of $1,000 per unit, or $8.0 million, plus $0.2 million of accrued dividends. The Partnership recognized $0.4 million of preferred dividends for the year ended December 31, 2011 which are presented as reductions of net income to determine the net income attributable to common limited partners and the General Partner on its consolidated statements of operations.

Class D Preferred Units

In November 2012, the Partnership entered into a unit purchase agreement for a private placement of $200.0 million of newly-created Class D convertible preferred units (Class D Preferred Units) to third party investors. The unit purchase agreement was intended to provide financing for a portion of the Cardinal Acquisition. The unit purchase agreement was terminated when the Partnership raised more than $150.0 million in common unit equity. The Partnership paid each investor a commitment fee equal to 2.0% of its commitment at the time of termination for a total expense of $4.0 million, which was recorded as other costs on the Partnership s consolidated statements of operations.

On May 7, 2013, the Partnership completed a private placement of $400.0 million of its Class D Preferred Units to third party investors, at a negotiated price per unit of $29.75, resulting in net proceeds of $397.7 million pursuant to the Class D preferred unit purchase agreement dated April 16, 2013 (the Commitment Date). The General Partner contributed $8.2 million to maintain its 2.0% general partnership interest upon the issuance of the Class D Preferred Units. The Partnership used the proceeds to fund a portion of the purchase price of the TEAK Acquisition (see Note 3). The Class D Preferred Units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The Partnership has the right to convert the Class D Preferred Units, in whole but not in part, beginning one year following their issuance, into an equal number of common units, subject to customary anti-dilution adjustments. Unless previously converted, all Class D Preferred Units will convert into common units on May 7, 2015. In the event of any liquidation, dissolution or winding up of the Partnership or the sale or other disposition of all or substantially all of the assets of the Partnership, the holders of the Class D Preferred Units are entitled to receive, out of the assets of the Partnership available for distribution to unit holders, prior and in preference to any distribution of any assets of the Partnership to the holders of any other existing or subsequently issued units, an amount equal to $29.75 per Class D Preferred Unit plus any unpaid preferred distributions.

Upon the issuance of the Class D Preferred Units, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class D Preferred Units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective within 180 days of the date of conversion.

The fair value of the Partnership s common units on April 16, 2013 was $36.52 per unit, resulting in an embedded beneficial conversion discount (discount) on the Class D Preferred Units of $91.0 million. The Partnership recognized the fair value of the Class D Preferred Units with the offsetting intrinsic value of the discount within Class D preferred limited partner interests on its consolidated balance sheets as of December 31, 2013. The discount will be accreted and recognized as imputed dividends over the term of the Class D Preferred Units as a reduction to net income attributable to the common limited partners and the General Partner on the Partnership s consolidated statements of operations. For the year ended December 31, 2013, the Partnership recorded $29.5 million within preferred unit imputed dividend effect on the Partnership s consolidated statements of operations to recognize the accretion of the beneficial conversion discount. The Class D Preferred Units are presented combined with a net $61.5 million unaccreted beneficial conversion discount on the Partnership s consolidated balance sheets as of December 31, 2013.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the Partnership s General Partner. Cash distributions will be paid to the Class D Preferred Unit holders prior to any other distributions of available cash. Distributions will be determined based upon the cash distribution declared each quarter on the Partnership s common limited partner units plus a preferred yield premium. Class D Preferred Unit distributions, whether in kind units or in cash, will be accounted for as a reduction to net income attributable to the common limited partners and the General Partner. For the year ended December 31, 2013, the Partnership recorded costs related to preferred unit distributions in kind of $23.6 million on the Partnership s consolidated statements of operations. During the year ended December 31, 2013, the Partnership distributed 378,486 Class D Preferred Units to the holders of the Class D Preferred Units. The Partnership considers preferred unit distributions paid in kind to be a non-cash financing activity.

125

Table of Contents

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. Based on this declaration, the Partnership issued 274,785 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended December 31, 2013 on February 14, 2014, to the preferred unitholders of record at the close of business on February 7, 2014.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

	December 31, 2013	December 31, 2012	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,885,303	$ 2,294,024	2 40
Rights of way	203,136	178,234	20 40
Buildings	10,291	8,224	40
Furniture and equipment	13,800	10,305	3 7
Other	15,805	14,761	3 10
	3,128,335	2,505,548	
Less accumulated depreciation	(404,143)	(305,167)	
	$ 2,724,192	$ 2,200,381	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of $99.7 million, $66.2 million and $54.3 million for the years ended December 31, 2013, 2012 and 2011, respectively, on its consolidated statements of operations.

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds was 5.8%, 6.4% and 7.0% for the years ended December 31, 2013, 2012 and 2011, respectively. The amount of interest capitalized was $7.5 million, $8.7 million and $5.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership owns and leases certain gas treating assets that are used to remove impurities from natural gas before it is delivered into gathering systems and transmission pipelines to ensure it meets pipeline quality specifications. These assets are included within pipelines, processing and compression facilities within property, plant and equipment on the Partnership s consolidated balance sheet. Revenues from these lease arrangements are recorded within transportation, processing and other fee revenues on the Partnership s consolidated statement of operations. Future minimum rental income related to these lease arrangements is estimated to be as follows for each of the next five calendar years: 2014 - $4.0 million; 2015 - $3.0 million; 2016 - $1.0 million; 2017 - 2018 - none.

Table of Contents

NOTE 7 GOODWILL AND INTANGIBLE ASSETS

The Partnership recorded goodwill on its consolidated balance sheets of $368.6 million and $319.3 million at December 31, 2013 and December 31, 2012, respectively. The change in goodwill is primarily related to an addition of $188.9 million of goodwill from the TEAK Acquisition partially offset by a $96.7 million reduction in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the Cardinal Acquisition and a $43.9 million reduction in goodwill related to an impairment of goodwill recorded for Gas Treating reporting unit acquired as part of the Cardinal Acquisition. The goodwill related to the Cardinal Acquisition is a result of the strategic industry position and potential future synergies. The goodwill related to the TEAK Acquisition is a result of the strategic industry position (see Note 3). The Partnership expects all goodwill recorded to be deductible for tax purposes.

Subsequent to recording the final estimated fair values of the assets acquired and liabilities assumed in the Cardinal Acquisition, the Partnership determined that a portion of goodwill recorded in connection with the acquisition was impaired. The Partnership performed a qualitative assessment for goodwill impairment on the Gas Treating reporting unit. The assessment indicated the potential for goodwill recorded on Gas Treating to be impaired due to lower forecasted cash flows as compared to original forecasts. Using a combination of discounted cash flow models and market multiples for similar businesses, the Partnership measured the amount of goodwill impairment on Gas Treating to be $43.9 million. The Partnership recorded a goodwill impairment loss of $43.9 million on its consolidated statements of operations for the year ended December 31, 2013.

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions including the Cardinal and TEAK Acquisitions. As part of the TEAK Acquisition, the Partnership recognized $450.0 million of customer relationships with an estimated useful life of 13 years. As part of the Cardinal Acquisition, the Partnership recognized $232.3 million of customer relationships with estimated useful lives of 8 to 15 years, and $0.4 million of customer contracts with an estimated useful life of 2 years. The following table reflects the components of intangible assets being amortized at December 31, 2013 and 2012 (in thousands):

Table of Contents

	December 31, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 3,419	$ 119,933	2 10
Customer relationships	887,653	205,313	7 15
	891,072	325,246	
Accumulated amortization:			
Customer contracts	(779)	(746)	
Customer relationships	(194,022)	(125,140)	
	(194,801)	(125,886)	
Net carrying amount:			
Customer contracts	2,640	119,187	
Customer relationships	693,631	80,173	
Net carrying amount	$ 696,271	$ 199,360	

The weighted-average amortization period for customer contracts and customer relationships is 9.4 years and 12.1 years, respectively. The Partnership recorded amortization expense on intangible assets of $68.9 million, $23.8 million and $23.1 million for the years ended December 31, 2013, 2012 and 2011, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2014 $78.0 million; 2015 through 2016 $72.8 million per year; 2017 $66.7 million per year; 2018 $58.3 million.

The valuation assessment for the TEAK Acquisition has not been completed as of December 31, 2013 and the estimates of fair value of goodwill and intangible assets with finite lives reflected as of December 31, 2013 are subject to change and the change may be material (see Note 3).

NOTE 8 OTHER ASSETS

The following is a summary of other assets (in thousands):

	December 31, 2013	December 31, 2012
Deferred finance costs, net of accumulated amortization of $22,034 and $23,536 at December 31, 2013 and 2012, respectively	$ 41,094	$ 30,496
Security deposits	5,367	2,097
	$ 46,461	$ 32,593

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred $22.8 million, $14.4 million and $4.2 million of deferred finance costs during the years ended December 31, 2013, 2012 and 2011, respectively, related to various financing activities (see Note 13). During the year ended December 31, 2013, the Partnership redeemed all of its outstanding $365.8 million 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) (see Note 13) and recognized accelerated amortization of deferred financing costs. During the years ended December 31, 2013 and 2011, the Partnership recorded $5.3 million and $5.2 million, respectively, related to accelerated amortization of deferred financing costs associated with the retirement of debt, which is included in loss on early extinguishment of debt on the Partnership s consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the year ended December 31, 2012. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was $7.0 million, $4.7 million and $4.5 million for the years ended December 31, 2013, 2012 and 2011, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations.

NOTE 9 INCOME TAXES

As part of the Cardinal Acquisition (see Note 3), the Partnership acquired APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership s taxable subsidiary for the years ended December 31, 2013 and 2012 are summarized as follows (in thousands):

	Years Ended December 31, 2013	2012
Deferred expense (benefit) :		
Federal	$ (2,024)	$ 158
State	(236)	18
Total income tax expense (benefit)	$ (2,260)	$ 176

The components of net deferred tax liabilities as of December 31, 2013 and 2012 consist of the following (in thousands):

	December 31, 2013	December 31, 2012
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	$ 14,900	$ 10,277
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(48,190)	(40,535)
Net deferred tax liabilities	$ (33,290)	$ (30,258)

As of December 31, 2013, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately $38.5 million, which expire at various dates from 2029 to 2033. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and put option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under its swap agreements, the Partnership receives a fixed price and remits a floating price based on certain indices for the relevant contract period. The swap agreement sets a fixed price for the product being hedged. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. A costless collar is a combination of a purchased put option and a sold call option, in which the premiums net to zero. A costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership s consolidated balance sheets, was reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affected earnings. The Partnership has reclassified all earnings out of accumulated other comprehensive income (loss), within equity on the Partnership s consolidated balance sheet and there was no balance outstanding as of the years ended December 31, 2013 and 2012.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of setoff at the time of settlement of the derivatives. Due to the right of setoff, derivatives are recorded on the Partnership s consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership s consolidated balance sheets as the initial value of the options. Changes in the fair value of the options are recognized within derivative gain (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative gain (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative liabilities on its consolidated balance sheet of $9.1 million at December 31, 2013, and net derivative assets of $31.0 million at December 31, 2012.

The following tables summarize the Partnership s gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets and liabilities on the Partnership s consolidated balance sheets for the periods indicated (in thousands):

Offsetting of Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
As of December 31, 2013:			
Current portion of derivative assets	$ 1,310	$ (1,136)	$ 174
Long-term portion of derivative assets	5,082	(2,812)	2,270
Current portion of derivative liabilities	1,612	(1,612)	
Long-term portion of derivative liabilities	949	(949)	
Total derivative assets, net	$ 8,953	$ (6,509)	$ 2,444
As of December 31, 2012:			
Current portion of derivative assets	$ 23,534	$ (457)	$ 23,077
Long-term portion of derivative assets	9,637	(1,695)	7,942

Total derivative assets, net	$ 33,171	$ (2,152)	$ 31,019

Table of Contents

Offsetting of Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
As of December 31, 2013:			
Current portion of derivative assets	$ (1,136)	$ 1,136	$
Long-term portion of derivative assets	(2,812)	2,812	
Current portion of derivative liabilities	(12,856)	1,612	(11,244)
Long-term portion of derivative liabilities	(1,269)	949	(320)
Total derivative liabilities, net	$ (18,073)	$ 6,509	$ (11,564)
As of December 31, 2012:			
Current portion of derivative liabilities	$ (457)	$ 457	$
Long-term portion of derivative liabilities	(1,695)	1,695	
Total derivative liabilities, net	$ (2,152)	$ 2,152	$

The following table summarizes the Partnership s commodity derivatives as of December 31, 2013, (fair value and volumes in thousands):

Production Period	Commodity	Volumes[(1)]	Average Fixed Price ($/Volume)	Fair Value[(2)] Asset/ (Liability)
Fixed price swaps				
2014	Natural gas	12,900	$ 3.98	$ (2,588)
2015	Natural gas	16,960	4.23	1,368
2016	Natural gas	6,150	4.30	950
2014	NGLs	82,404	1.18	(9,791)
2015	NGLs	41,454	1.08	(2,083)
2016	NGLs	6,300	1.03	(92)
2014	Crude oil	312	92.37	(1,245)
2015	Crude oil	60	85.13	(186)
Total fixed price swaps				(13,667)
Purchased Put Options				

2014	Natural gas	600	4.13		168
2014	NGLs	4,410	1.00		100
2015	NGLs	1,890	0.90		110
2014	Crude oil	449	94.69		2,019
2015	Crude oil	270	89.18		2,150
Total options					4,547
Total derivatives				$	(9,120)

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 11 for discussion on fair value methodology.

131

Table of Contents

The following tables summarize the gross effect of all derivative instruments on the Partnership s consolidated statements of operations for the periods indicated (in thousands):

	For the Years ended December 31, 2013	2012	2011
Derivatives previously designated as cash flow hedges			
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	$	$ (4,390)	$ (6,834)
Derivatives not designated as hedges			
Gain (loss) recognized in derivative gain (loss), net:			
Commodity contract realized (1)	$ (324)	$ 10,993	$ (13,123)
Commodity contract unrealized (2)	(28,440)	20,947	(7,329)
Derivative gain (loss), net	$ (28,764)	$ 31,940	$ (20,452)

(1) Realized gain (loss) represents the gain or loss incurred when the derivative contract expires and/or is cash settled.

(2) Unrealized gain (loss) represents the mark-to-market gain or loss recognized on open derivative contracts, which have not yet settled.

NOTE 11 FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership s own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into Levels 1, 2 and 3 (see Note 2 Fair Value of Financial Instruments).

Derivative Instruments

At December 31, 2013, the valuations for all the Partnership s derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership s NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership s Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange (NYMEX) quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Valuations for the Partnership s NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Table of Contents

Valuations for the Partnership s NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

The following table represents the Partnership s derivative assets and liabilities recorded at fair value as of December 31, 2013 and 2012 (in thousands):

	Level 1	Level 2	Level 3	Total
December 31, 2013				
Assets				
Commodity swaps	$	$ 2,994	$ 1,412	$ 4,406
Commodity options		4,337	210	4,547
Total assets		7,331	1,622	8,953
Liabilities				
Commodity swaps		(4,695)	(13,378)	(18,073)
Total liabilities		(4,695)	(13,378)	(18,073)
Total derivatives	$	$ 2,636	$ (11,756)	$ (9,120)
December 31, 2012				
Assets				
Commodity swaps	$	$ 2,007	$ 17,573	$ 19,580
Commodity options		7,322	6,269	13,591
Total assets		9,329	23,842	33,171
Liabilities				
Commodity swaps		(1,393)	(759)	(2,152)
Total liabilities		(1,393)	(759)	(2,152)
Total derivatives	$	$ 7,936	$ 23,083	$ 31,019

Table of Contents

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the years ended December 31, 2013 and 2012 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance January 1, 2012	49,644	$ (1,733)	92,610	$ 18,279	$ 16,546
New contracts(1)	84,294				
Cash settlements from unrealized gain (loss)(2)(3)	(46,872)	(7,863)	(54,054)	(142)	(8,005)
Net change in unrealized gain (loss)(2)		26,410		923	27,333
Deferred option premium recognition(3)				(12,791)	(12,791)
Balance December 31, 2012	87,066	$ 16,814	38,556	$ 6,269	$ 23,083
New contracts(1)	104,328		7,560	816	816
Cash settlements from unrealized gain (loss)(2)(3)	(61,236)	(11,496)	(39,816)	8,545	(2,951)
Net change in unrealized gain (loss)(2)		(17,284)		(2,367)	(19,651)
Deferred option premium recognition(3)				(13,053)	(13,053)
Balance December 31, 2013	130,158	$ (11,966)	6,300	$ 210	$ (11,756)

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.
(2) Included within derivative gain (loss), net on the Partnership s consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership s NGL fixed price swaps at December 31, 2013 and 2012 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of December 31, 2013				
Propane swaps	100,296	$ (10,260)	$	$ (10,260)
Isobutane swaps	6,300	(2,342)	955	(1,387)
Normal butane swaps	7,560	40	322	362
Natural gasoline swaps	16,002	132	(813)	(681)
Total NGL swaps December 31, 2013	130,158	$ (12,430)	$ 464	$ (11,966)
As of December 31, 2012				
Propane swaps	69,678	$ 16,302	$ (552)	$ 15,750
Isobutane swaps	1,134	(219)	187	(32)
Normal butane swaps	6,174	(909)	242	(667)

Natural gasoline swaps		10,080		3,247		(1,484)	1,763
Total NGL swaps	December 31, 2012	87,066	$	18,421	$	(1,607)	$ 16,814

(1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.

(2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

Table of Contents

The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

		Level 3 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient Lower 95%	Upper 95%	Average
As of December 31, 2013:					
Isobutane		955	1.1184	1.1284	1.1234
Normal butane		322	1.0341	1.0386	1.0364
Natural gasoline		(813)	0.9727	0.9751	0.9739
Total Level 3 adjustments	December 31, 2013	$ 464			
As of December 31, 2012:					
Propane		$ (552)	0.9019	0.9122	0.9071
Isobutane		187	1.1285	1.1376	1.1331
Normal butane		242	1.0370	1.0416	1.0393
Natural gasoline		(1,484)	0.8988	0.9169	0.9078
Total Level 3 adjustments	December 31, 2012	$ (1,607)			

NGL Linefill

The Partnership had $14.5 million and $7.8 million of NGL linefill at December 31, 2013 and 2012, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties, for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership s NGL linefill held by one counterparty will be settled at various periods in the future and is defined as a Level 3 asset, which is valued using the same forward price curve utilized to value the Partnership s NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of $0.4 million and $0.4 million as of December 31, 2013 and 2012, respectively. The Partnership s NGL linefill held by other counterparties is adjusted on a monthly basis according to the volumes delivered to the counterparties each period and is valued on a first in first out (FIFO) basis.

Table of Contents

The following table provides a summary of changes in fair value of the Partnership s NGL linefill for the years ended December 31, 2013 and 2012 (in thousands):

	Linefill Valued at Market		Linefill Valued on FIFO		Total NGL Linefill	
	Gallons	Amount	Gallons	Amount	Gallons	Amount
Balance December 31, 2011	10,408	$ 11,529		$	10,408	$ 11,529
Cash Settlements(1)	(2,520)	(2,698)			(2,520)	(2,698)
Net change in NGL linefill valuation(1)		(2,111)				(2,111)
Acquired NGL linefill(2)	1,260	1,063			1,260	1,063
Balance December 31, 2012	9,148	$ 7,783		$	9,148	$ 7,783
Deliveries into NGL linefill			80,758	60,565	80,758	60,565
NGL linefill sales	(3,360)	(2,795)	(71,433)	(52,155)	(74,793)	(54,950)
Net change in NGL linefill valuation(1)		(249)				(249)
Acquired NGL linefill(2)			2,213	1,368	2,213	1,368
Balance December 31, 2013	5,788	$ 4,739	11,538	$ 9,778	17,326	$ 14,517

(1) Included within natural gas and liquid sales on the Partnership s consolidated statements of operations.
(2) NGL linefill acquired as part of the Cardinal and TEAK Acquisitions (see Note 3).

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of $19.0 million. The Partnership agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period (Trigger Payments). Sufficient volumes were achieved in December 2012 and the Partnership paid the first Trigger Payment of $6.0 million in January 2013. As of December 31, 2013, the fair value of the remaining Trigger Payment resulted in a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership s consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining Trigger Payment is between $0.0 and $6.0 million.

Other Financial Instruments

The estimated fair value of the Partnership s other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership s current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level

1 value. The estimated fair value of the Partnership s Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership s total debt at December 31, 2013 and 2012, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,663.6 million and $1,216.4 million, respectively, compared with the carrying amounts of $1,707.3 million and $1,179.9 million, respectively.

Table of Contents

Acquisitions

On December 20, 2012, the Partnership completed the Cardinal Acquisition (see Note 3). On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation. The estimates of fair value of the TEAK assets as of the acquisition date, which are reflected in the Partnership s consolidated balance sheet as of December 31, 2013, are subject to change as the final valuation has not yet been completed, and such changes may be material (see Note 3).

NOTE 12 ACCRUED LIABILITIES

The following is a summary of accrued liabilities (in thousands):

	December 31, 2013	December 31, 2012
Accrued capital expenditures	$ 17,898	$ 8,336
Acquisition-related liabilities	8,933	
Cardinal Acquisition payable (offset by funds in escrow)		25,000
Acquisition-based short-term contingent consideration		6,000
Accrued ad valorem and production taxes	3,551	3,950
Other	17,067	14,466
	$ 47,449	$ 57,752

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	December 31, 2013	December 31, 2012
Revolving credit facility	$ 152,000	$ 293,000
8.750% Senior notes due 2018		370,184
6.625% Senior notes due 2020	504,556	505,231
5.875% Senior notes due 2023	650,000	
4.750% Senior notes due 2021	400,000	
Capital lease obligations	754	11,503
Total debt	1,707,310	1,179,918
Less current maturities	(524)	(10,835)
Total long term debt	$ 1,706,786	$ 1,169,083

137

Table of Contents

The aggregate amount of the Partnership s debt maturities is as follows (in thousands):

Years Ended December 31:	
2014	$ 524
2015	225
2016	5
2017	152,000
2018	
Thereafter	1,550,000
Total principal maturities	1,702,754
Unamortized premium	4,556
Total debt	$ 1,707,310

Cash payments for interest related to debt, net of capitalized interest, were $66.3 million, $28.3 million and $27.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Revolving Credit Facility

At December 31, 2013, the Partnership had a $600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. Borrowings under the revolving credit facility bear interest, at the Partnership s option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at December 31, 2013, was 4.0%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.1 million was outstanding at December 31, 2013. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At December 31, 2013, the Partnership had $447.9 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by (i) a lien on and security interest in all the Partnership s property and that of its subsidiaries, except for the assets owned by Atlas Pipeline Mid-Continent WestOk, LLC (WestOK LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX LLC), entities in which the Partnership has 95% interests, and Centrahoma, in which the Partnership has a 60% interest; and their respective subsidiaries; and (ii) by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including requirements that the Partnership maintain certain financial thresholds and restrictions on the Partnership s ability to (1) incur additional indebtedness, (2) make certain acquisitions, loans or investments, (3) make distribution payments to its unitholders if an event of default exists, or (4) enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is unable to borrow under its revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner.

138

On April 19, 2013, the Partnership entered into an amendment to the 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 the Class D Preferred Units so long as the Partnership has 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.

As of December 31, 2013, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At December 31, 2013, the Partnership had $500.0 million principal outstanding of 6.625% Senior Notes, $650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes), and $400.0 million of 4.75% Senior Notes (with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes).

The Senior Notes are subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its revolving credit facility.

Indentures governing the Senior Notes contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of December 31, 2013.

6.625% Senior Notes

The 6.625% Senior Notes are presented combined with a net $4.6 million unamortized premium as of December 31, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

On September 28, 2012, the Partnership issued $325.0 million of the 6.625% Senior Notes in a private placement transaction, at par. The Partnership received net proceeds of $318.9 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on its revolving credit facility.

On December 20, 2012, the Partnership issued $175.0 million of the 6.625% Senior Notes in a private placement transaction. The 6.625% Senior Notes were issued at a premium of 103.0% of the principal amount for a yield of 6.0%. The Partnership received net proceeds of $176.1 million after underwriting commissions and other transaction costs and utilized the proceeds to partially finance the Cardinal Acquisition (see Note 3). Of the $176.1 million net proceeds, $176.5 million was received during the year ended December 31, 2012, while additional expenses of $0.4 million were incurred during the year ended December 31, 2013.

The Partnership commenced an exchange offering for the 6.625% Senior Notes on September 18, 2013 and the exchange offer was completed on October 16, 2013. Pursuant to the terms of the registration rights agreement related to the 6.625% Senior Notes, because the exchange offer was not consummated within the aforementioned timeframe, the Partnership incurred a 0.25% interest penalty of $52 thousand for the period from September 23, 2013 through consummation of the exchange offer on October 16, 2013.

8.125% Senior Notes

On April 8, 2011, the Partnership redeemed all the 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes). The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. For the year ended December 31, 2011, the Partnership recorded a loss of $19.4 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the redemption of the 8.125% Senior Notes. The loss includes the $11.2 million premium paid; a $3.1 million write off of unamortized discount; and a $5.1 million write off of deferred financing costs.

8.75% Senior Notes

On April 7, 2011, the Partnership redeemed $7.2 million of the 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes), which were tendered upon its offer to purchase the 8.75% Senior Notes, at par. The Laurel Mountain Sale (see Note 4) constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, the Partnership offered to purchase any and all of the 8.75% Senior Notes. For the year ended December 31, 2011, the Partnership recorded a loss of $0.2 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the write off of deferred financing costs for the 8.75% Senior Notes.

On November 21, 2011, the Partnership issued $150.0 million of the 8.75% Senior Notes in a private placement transaction. The 8.75% Senior Notes were issued at a premium of 103.5% of the principal amount for a yield of 7.82%. The Partnership received net proceeds of $152.4 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on its revolving credit facility.

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding $365.8 million 8.75% Senior Notes, excluding unamortized premium, and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default 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 were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and $8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture.

On March 12, 2013, the Partnership paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes. During the year ended December 31, 2013, the Partnership recorded a loss of $26.6 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the redemption of the 8.75% Senior Notes. The loss includes $17.5 million premiums paid; $8.0 million consent payment; $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium.

5.875% Senior Notes

On February 11, 2013, the Partnership issued $650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of $637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Partnership commenced an exchange offer for the 5.875% Senior Notes on December 10, 2013 and the exchange offer was completed on January 9, 2014.

4.75% Senior Notes

On May 10, 2013, the Partnership issued $400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. The Partnership received net proceeds of $391.2 million after underwriting commissions and other transactions costs and utilized the proceeds to repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Note 3). Interest on the 4.75% Senior Notes is payable semi-annually in arrears on May 15 and November 15. The 4.75% Senior Notes are due on November 15, 2021 and are redeemable any time after March 15, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Partnership commenced an exchange offer for the 4.75% Senior Notes on December 10, 2013 and the exchange offer was completed on January 9, 2014.

Capital Leases

During the year ended December 31, 2013, the Partnership accelerated payment on certain leases and purchased the leased property by paying approximately $7.5 million in accordance with the lease agreements. These leases were to mature in August 2013.

During the year ended December 31, 2012, the Partnership recorded $1.9 million related to new capital lease agreements within property, plant and equipment and recorded an offsetting liability within long-term debt on the Partnership s consolidated balance sheets. This amount was based upon the minimum payments required under the leases and the Partnership s incremental borrowing rate. As part of the Cardinal Acquisition (see Note 3), the Partnership acquired an additional $0.9 million of capital leases during the year ended December 31, 2012.

The following is a summary of the leased property under capital leases as of December 31, 2013 and 2012, which are included within property, plant and equipment (see Note 6) (in thousands):

	December 31, 2013	December 31, 2012
Pipelines, processing and compression facilities	$ 2,281	$ 15,457
Less accumulated depreciation	(330)	(1,066)
	$ 1,951	$ 14,391

Depreciation expense for leased properties was $340 thousand, $723 thousand and $152 thousand for the years ended December 31, 2013, 2012 and 2011, respectively, which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 6).

As of December 31, 2013, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2014	$ 524
2015	225
2016	5
2017	
2018	
Thereafter	
Total minimum lease payments	754
Less amounts representing interest	(26)
Present value of minimum lease payments	728
Less current portion of capital lease obligations	(503)
Long-term capital lease obligations	$ 225

NOTE 14 COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space that expire at various dates. Certain operating leases provide the Partnership with the option to renew for additional periods. Where operating leases contain escalation clauses, rent abatements, and/or concessions, the Partnership applies them in the determination of straight-line rent expense over the lease term. Leasehold improvements are amortized over the shorter of the lease term or asset life, which may include renewal periods where the renewal is reasonably assured, and is included in the determination of straight-line rent expense. Total rental expense for the years ended December 31, 2013, 2012 and 2011 was $11.3 million, $5.5 million and $5.5 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2013 is as follows (in thousands):

Years Ended December 31:	
2014	$ 4,629
2015	4,042
2016	3,638
2017	842
2018	745
Thereafter	965
	$ 14,861

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership s operations. Transportation fees paid related to these contracts, including minimum shipment payments, were $34.8 million, $10.5 million and $10.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. The future fixed and determinable portion of the obligations as of December 31, 2013 was as follows: 2014 $9.5 million; 2015 to 2017 $3.5 million per year; and 2018 $2.7 million.

The Partnership had committed approximately $102.5 million for the purchase of property, plant and equipment at December 31, 2013.

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

NOTE 15 CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas, NGLs and condensate under contract to various purchasers in the normal course of business, within the Gathering and Processing segment (see Note 18). For the year ended December 31, 2013, the Partnership had three customers that individually accounted for approximately 29%, 17% and 14%, respectively, of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2012, the Partnership had two customers that individually accounted for approximately 48% and 15%, respectively, of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2011, the Partnership had two customers that individually accounted for approximately 60% and 16%, respectively, of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. Additionally, the Partnership had three customers that individually accounted for approximately 23%, 20%, and 10%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2013, and two customers that individually accounted for approximately 45% and 14%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2012.

The Partnership has certain producers that supply a majority of the natural gas to its gathering systems and processing facilities. A reduction in the volume of natural gas that any one of these producers supply to the Partnership could adversely affect its operating results unless comparable volume could be obtained from other producers in the surrounding region.

Table of Contents

The Partnership places its temporary cash investments in high quality short-term money market instruments and deposits with high quality financial institutions. At December 31, 2013, the Partnership and its subsidiaries had $5.7 million in deposits at banks, of which $5.3 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 16   BENEFIT PLANS

Share-based payments to employees, which are not cash settled, including grants of unit options and phantom units, are recognized within equity in the financial statements based on their fair values on the date of the grant. Share-based payments to non-employees that have a cash settlement option are recognized within liabilities in the financial statements based upon their current fair market value.

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. The compensation committee appointed by the General Partner s managing board (the Compensation Committee) determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The Compensation Committee determines how the exercise price may be paid by the grantee as well as the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan (2010 LTIP and collectively with the 2004 LTIP, the LTIPs) in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner s affiliates and consultants are eligible to participate. The LTIPs are administered by the Compensation Committee. Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At December 31, 2013, the Partnership had 1,446,553 phantom units outstanding under the Partnership s LTIPs, with 840,870 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options that have vested and have been exercised.

Partnership Phantom Units

Through December 31, 2013, phantom units granted to employees under the LTIPs generally had vesting periods of four years. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 equity indexed bonus units (Bonus Units), under the Partnership s subsidiary s plan discussed below, agreed to exchange their Bonus Units for an equivalent number of phantom units. These phantom units vested over a three year period. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At December 31, 2013, there were 464,452 units outstanding under the LTIPs that will vest within the following twelve months.

144

Table of Contents

The Partnership is authorized to purchase common units from employees to cover employee-related taxes when certain phantom units have vested. During the years ended December 31, 2012 and 2011, the Partnership purchased and retired 24,052 common units and 28,878 common units, respectively, to cover employee-related taxes, for a cost of $0.7 million and $1.0 million, respectively. The purchased and retired units were recorded as a reduction of equity on the Partnership s consolidated balance sheet. There were no phantom units purchased and retired during the year ended December 31, 2013.

On February 17, 2011, the employment agreement with the Chief Executive Officer (CEO) of the General Partner was terminated in connection with the Chevron Merger (see Note 4) and 75,250 outstanding phantom units, which represents all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at December 31, 2013 include DERs granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $3.1 million, $2.0 million and $0.8 million during the years ended December 31, 2013, 2012 and 2011, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

The following table sets forth the Partnership s LTIPs phantom unit activity for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	1,053,242	$ 33.21	394,489	$ 21.63	490,886	$ 11.75
Granted	744,997	38.96	907,637	34.94	178,318	33.47
Forfeited	(61,550)	36.11	(67,675)	29.83	(41,250)	13.49
Matured and issued(2)(3)	(290,136)	31.88	(181,209)	17.88	(233,465)	11.34
Outstanding, end of period(4)(5)	1,446,553	$ 36.32	1,053,242	$ 33.21	394,489	$ 21.63
Non-cash compensation expense recognized (in thousands)(6)		$ 19,344		$ 11,635		$ 3,271

(1) Fair value based upon weighted average grant date price.
(2) The intrinsic values for phantom unit awards exercised during the years ended December 31, 2013, 2012 and 2011 were $10.7 million, $5.5 million and $7.4 million, respectively.
(3) There were 1,677 phantom units; 792 phantom units; and 414 phantom units, which were settled for $58 thousand, $26 thousand and $14 thousand cash during the years ended December 31, 2013, 2012 and 2011, respectively.
(4) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2013 and 2012 was $50.7 million and $33.3 million, respectively.
(5) There were 22,539 and 17,926 outstanding phantom unit awards at December 31, 2013 and 2012, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.
(6)

Non-cash compensation expense includes incremental compensation expense of $472 thousand, related to the accelerated vesting of phantom units held by the CEO of the General Partner during the year ended December 31, 2011.

At December 31, 2013, the Partnership had approximately $30.8 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

145

Table of Contents

Partnership Unit Options

At December 31, 2013, there were no unit options outstanding. On February 17, 2011, the employment agreement with the CEO of the General Partner was terminated in connection with the Chevron Merger (see Note 4) and 50,000 outstanding unit options held by the CEO automatically vested. As of December 31, 2013, all unit options had been exercised.

The following table sets forth the LTIP unit option activity for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period		$		$	75,000	$ 6.24
Granted						
Exercised[(1)]					(75,000)	6.24
Outstanding, end of period						
Weighted average fair value of unit options per unit granted during the period		$		$		$
Non-cash compensation expense recognized (in thousands)[(2)]		$		$		$ 3

(1) The intrinsic value for option unit awards exercised during the year ended December 31, 2011 was $1.7 million. Approximately $0.5 million was received from exercise of unit option awards during the year ended December 31, 2011.
(2) Non-cash compensation expense includes incremental compensation expense of $2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner, during the year ended December 31, 2011.

Employee Incentive Compensation Plan and Agreement

Atlas Pipeline Mid-Continent LLC, a wholly-owned subsidiary of the Partnership, has an incentive plan (the APLMC Plan), which allowed for equity-indexed cash incentive awards to employees of the Partnership (the Participants). The APLMC Plan was administered by a committee appointed by the CEO of the General Partner. Under the APLMC Plan, cash bonus units (Bonus Unit) were awarded to Participants at the discretion of the committee. A Bonus Unit entitled the employee to receive the cash equivalent of the then fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vested ratably over a three year period from the date of grant and automatically vested upon a change of control, death, or termination without cause, each as defined in the governing document. During the years ended December 31, 2012 and 2011, 25,500 and 24,750 Bonus Units, respectively, vested and cash payments were made for $0.7 million and $0.9 million, respectively. All outstanding bonus units became fully vested at the end of December 31, 2012. The Partnership recognized income of

$79 thousand during the year ended December 31, 2012 and expense of $862 thousand during the year ended December 31, 2011, which was recorded within general and administrative expense on its consolidated statements of operations. No expense was recognized during the year ended December 31, 2013. At December 31, 2013 and 2012, Atlas Pipeline Mid-Continent LLC had no outstanding Bonus Units under the APLMC Plan and does not anticipate any further grants thereunder.

NOTE 17 RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of ATLS. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by ATLS based on the number of its employees who devote their time to activities on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $5.0 million, $3.8 million and $1.8 million for the years ended December 31, 2013, 2012 and 2011, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the years ended December 31, 2013, 2012 and 2011. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) (ARP) on its gathering systems located in Tennessee. ARP s general partner is wholly-owned by ATLS, and two members of the General Partner s managing board are members of ARP s board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP s leases, in February 2008. The Partnership charged ARP approximately $0.3 million, $0.4 million and $0.3 million in compression and gathering fees for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership agreed to provide design, procurement and construction management services for ARP with respect to a pipeline located in Lycoming County, Pennsylvania (the Lycoming Pipeline). The Partnership has been reimbursed approximately $1.8 million by ARP for these services during the year ended December 31, 2013.

On February 17, 2011, the Partnership completed the Laurel Mountain Sale to Atlas Energy Resources for $409.5 million, including closing adjustments and net of expenses (See Note 4).

In connection with the TEAK Acquisition, the Partnership sold approximately 3.4 million of its Class D Preferred Units for approximately $100.0 million (See Note 5) to Omega Capital and its affiliates, which beneficially owned more than 5% of the Partnership s outstanding limited partnership units as of December 31, 2013. The sale of the Class D Preferred Units was made to Omega Capital and its affiliates upon substantially the same terms as unrelated third parties that also purchased Class D Preferred Units in connection with the TEAK Acquisition and was approved in advance by the Partnership s Conflicts Committee.

NOTE 18 SEGMENT INFORMATION

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating). These reportable segments reflect the way the Partnership manages its operations.

Table of Contents

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 Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of (1) the Gas Treating operations, which own contract gas treating facilities located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; (2) the Partnership s 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation; 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 Note 4). Gas Treating revenues are primarily derived from monthly lease fees for use of the treating facilities. Pipeline revenues are primarily derived from transportation fees.

In connection with the TEAK Acquisition (see Note 3), the Partnership 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.

The following summarizes the Partnership s reportable segment data for the periods indicated (in thousands):

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2013:				
Revenue:				
Revenues third party[1]	$ 2,129,414	$ 5,659	$ (28,527)	$ 2,106,546
Revenues affiliates	303			303
Total revenues	2,129,717	5,659	(28,527)	2,106,849
Costs and Expenses:				
Operating costs and expenses	1,783,551	1,358		1,784,909
General and administrative[1]			60,856	60,856
Other costs[2]			20,005	20,005
Depreciation and amortization	164,628	3,015	974	168,617
Interest expense[1]			89,637	89,637
Total costs and expenses	1,948,179	4,373	171,472	2,124,024
Equity income (loss) in joint ventures	(9,724)	4,988		(4,736)
Goodwill impairment loss		(43,866)		(43,866)
Loss on asset disposition	(1,519)			(1,519)
Loss on early extinguishment of debt			(26,601)	(26,601)

Income (loss) from continuing operations before tax	170,295	(37,592)	(226,600)	(93,897)
Income tax benefit	(2,260)			(2,260)
Net income (loss)	$ 172,555	$ (37,592)	$ (226,600)	$ (91,637)

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

(2) For the year ended December 31, 2013, acquisition costs related to the TEAK Acquisition are carried at the corporate level.

Table of Contents

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2012:				
Revenue:				
Revenues third party[1]	$ 1,217,820	$ 182	$ 27,583	$ 1,245,585
Revenues affiliates	435			435
Total revenues	1,218,255	182	27,583	1,246,020
Costs and Expenses:				
Operating costs and expenses	989,864	180		990,044
General and administrative[1]			47,206	47,206
Other costs[2]	(303)		15,372	15,069
Depreciation and amortization	90,029			90,029
Interest expense[1]			41,760	41,760
Total costs and expenses	1,079,590	180	104,338	1,184,108
Equity income in joint ventures		6,323		6,323
Income (loss) from continuing operations before tax	138,665	6,325	(76,755)	68,235
Income tax expense	176			176
Net income (loss)	$ 138,489	$ 6,325	$ (76,755)	$ 68,059

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

(2) For the year ended December 31, 2012, acquisition costs related to the Cardinal Acquisition are carried at the corporate level.

Table of Contents

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2011:				
Revenue:				
Revenues third party[1]	$ 1,329,686	$	$ (27,287)	$ 1,302,399
Revenues affiliates	335			335
Total revenues	1,330,021		(27,287)	1,302,734
Costs and Expenses:				
Operating costs and expenses	1,102,330	214		1,102,544
General and administrative[1]			36,357	36,357
Other costs	330	710		1,040
Depreciation and amortization	77,435			77,435
Interest expense[1]			31,603	31,603
Total costs and expenses	1,180,095	924	67,960	1,248,979
Equity income in joint ventures	462	4,563		5,025
Gain on asset disposition	256,272			256,272
Loss on early extinguishment of debt			(19,574)	(19,574)
Income (loss) from continuing operations	406,660	3,639	(114,821)	295,478
Loss from discontinued operations			(81)	(81)
Net income (loss)	$ 406,660	$ 3,639	$ (114,902)	$ 295,397

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

	Years Ended December 31,		
Capital Expenditures:	**2013**	**2012**	**2011**
Gathering and processing	$ 446,820	$ 373,533	$ 245,426
Transportation and treating	99		
Corporate and other	3,641		
	$ 450,560	$ 373,533	$ 245,426

150

Table of Contents

Balance Sheet	December 31, 2013	December 31, 2012
Equity method investment in joint ventures:		
Gathering and processing	$ 162,511	$
Transportation and treating	85,790	86,002
	$ 248,301	$ 86,002
Goodwill:		
Gathering and processing	$ 368,572	$ 292,448
Transportation and treating		26,837
	$ 368,572	$ 319,285
Total assets:		
Gathering and processing	$ 4,146,314	$ 2,831,639
Transportation and treating	132,152	141,356
Corporate and other	49,379	92,643
	$ 4,327,845	$ 3,065,638

The following table summarizes the Partnership s natural gas and liquids sales by product or service for the periods indicated (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Natural gas and liquids sales:			
Natural gas	$ 708,817	$ 396,867	$ 400,991
NGLs	1,132,481	657,271	795,122
Condensate	118,095	85,234	72,037
Other	(249)	(2,111)	45
Total	$ 1,959,144	$ 1,137,261	$ 1,268,195

NOTE 19 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements include the financial statements of WestOK LLC, WestTX LLC and Centrahoma as well as the Partnership s equity interests in WTLPG and the T2 Joint Ventures. Under the terms of the Senior Notes and the revolving credit facility, WestOK LLC, WestTX LLC, Centrahoma, WTLPG, and the T2 Joint Ventures are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

151

Table of Contents

Balance Sheets December 31, 2013	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 168	$ 4,746	$	$ 4,914
Accounts receivable affiliates	765,236			(765,236)	
Other current assets	215	52,910	185,975	(2,236)	236,864
Total current assets	765,451	53,078	190,721	(767,472)	241,778
Property, plant and equipment, net		723,302	2,000,890		2,724,192
Intangible assets, net		603,533	92,738		696,271
Goodwill		323,678	44,894		368,572
Equity method investment in joint ventures			248,301		248,301
Long term portion of derivative assets		2,270			2,270
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	3,186,938	1,487,358		(4,674,296)	
Other assets, net	41,094	1,787	3,580		46,461
Total assets	3,993,483	3,195,006	$ 4,434,052	(7,294,696)	$ 4,327,845
Liabilities and Equity					
Accounts payable affiliates	$	$ 423,078	$ 345,070	$ (765,236)	$ 2,912
Other current liabilities	26,819	75,031	215,464		317,314
Total current liabilities	26,819	498,109	560,534	(765,236)	320,226
Long-term portion of derivative liabilities		320			320
Long-term debt, less current portion	1,706,556	230			1,706,786
Deferred income taxes, net		33,290			33,290
Other long-term liability	203	1,115	6,000		7,318
Equity	2,259,905	2,661,942	3,867,518	(6,529,460)	2,259,905
Total liabilities and equity	$ 3,993,483	$ 3,195,006	$ 4,434,052	$ (7,294,696)	$ 4,327,845

Table of Contents

December 31, 2012	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 157	$ 3,241	$	$ 3,398
Accounts receivable affiliates	921,702			(921,702)	
Other current assets	172	68,144	149,507	(1,146)	216,677
Total current assets	921,874	68,301	152,748	(922,848)	220,075
Property, plant and equipment, net		491,790	1,708,591		2,200,381
Intangible assets, net		101,446	97,914		199,360
Goodwill		278,423	40,862		319,285
Equity method investment in joint venture		86,002			86,002
Long term portion of derivative assets		7,942			7,942
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,832,652	1,880,155		(3,712,807)	
Other assets, net	30,496	1,772	325		32,593
Total assets	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638
Liabilities and Equity					
Accounts payable affiliates	$	$ 145,436	$ 781,766	$ (921,702)	$ 5,500
Other current liabilities	10,046	61,333	176,640		248,019
Total current liabilities	10,046	206,769	958,406	(921,702)	253,519
Long-term debt, less current portion	1,168,415	604	64		1,169,083
Deferred income taxes, net		30,258			30,258
Other long-term liability	153	217	6,000		6,370
Equity	1,606,408	2,677,983	2,888,898	(5,566,881)	1,606,408
Total liabilities and equity	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638

Table of Contents

Statements of Operations and Comprehensive Income	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2013					
Total revenues	$	$ 504,392	$ 1,684,625	$ (82,168)	$ 2,106,849
Total costs and expenses	(86,965)	(610,208)	(1,507,806)	80,955	(2,124,024)
Equity income (loss)	14,954	160,371	(4,736)	(175,325)	(4,736)
Goodwill impairment loss		(43,866)			(43,866)
Loss on early extinguishment of debt	(26,601)				(26,601)
Loss on asset disposition		(1,519)			(1,519)
Income (loss), before tax	(98,612)	9,170	172,083	(176,538)	(93,897)
Income tax benefit		(2,260)			(2,260)
Net income (loss)	(98,612)	11,430	172,083	(176,538)	(91,637)
Income attributable to non-controlling interest			(6,975)		(6,975)
Preferred unit imputed dividend effect	(29,485)				(29,485)
Preferred unit dividends in kind	(23,583)				(23,583)
Net income (loss) attributable to common limited partners and the General Partner	$ (151,680)	$ 11,430	$ 165,108	$ (176,538)	$ (151,680)
Year Ended December 31, 2012					
Total revenues	$	$ 240,679	$ 1,005,341	$	$ 1,246,020
Total costs and expenses	(39,462)	(272,284)	(872,362)		(1,184,108)
Equity income (loss)	101,511	139,339		(234,527)	6,323
Income (loss), before tax	62,049	107,734	132,979	(234,527)	68,235
Income tax expense		176			176
Net income (loss)	62,049	107,558	132,979	(234,527)	68,059
Income attributable to non-controlling interest			(6,010)		(6,010)
Net income (loss) attributable to common limited partners and the General Partner	62,049	107,558	126,969	(234,527)	62,049
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	4,390	4,390		(4,390)	4,390
Comprehensive income (loss)	$ 66,439	$ 111,948	$ 126,969	$ (238,917)	$ 66,439

Table of Contents

Statements of Operations and Comprehensive Income	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2011					
Total revenues	$	$ 238,047	$ 1,064,687	$	$ 1,302,734
Total costs and expenses	(28,682)	(292,818)	(927,479)		(1,248,979)
Equity income (loss)	341,355	139,480		(475,810)	5,025
Loss on early extinguishment of debt	(19,574)				(19,574)
Gain on asset sales and other		256,272			256,272
Income (loss) from continuing operations	293,099	340,981	137,208	(475,810)	295,478
Loss from discontinued operations		(81)			(81)
Net income (loss)	293,099	340,900	137,208	(475,810)	295,397
Income attributable to non-controlling interest			(6,200)		(6,200)
Preferred unit dividends	(389)				(389)
Net income (loss) attributable to common limited partners and the General Partner	292,710	340,900	131,008	(475,810)	288,808
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	6,834	6,834		(6,834)	6,834
Comprehensive income (loss)	$ 299,544	$ 347,734	$ 131,008	$ (482,644)	$ 295,642

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2013					
Net cash provided by (used in):					
Operating activities	$ (493,139)	$ 136,862	$ 281,141	$ 285,980	$ 210,844
Investing activities	(757,365)	(806,159)	(577,527)	697,968	(1,443,083)
Financing activities	1,250,504	669,308	297,891	(938,948)	1,233,755
Net change in cash and cash equivalents		11	1,505		1,516
Cash and cash equivalents, beginning of period		157	3,241		3,398
Cash and cash equivalents, end of period	$	$ 168	$ 4,746	$	$ 4,914

Table of Contents

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2012					
Net cash provided by (used in):					
Operating activities	$ (432,255)	$ 133,153	$ 186,494	$ 287,246	$ 174,638
Investing activities	(405,501)	(431,835)	(419,427)	250,122	(1,006,641)
Financing activities	837,756	298,671	236,174	(537,368)	835,233
Net change in cash and cash equivalents		(11)	3,241		3,230
Cash and cash equivalents, beginning of period		168			168
Cash and cash equivalents, end of period	$	$ 157	$ 3,241	$	$ 3,398
Year Ended December 31, 2011					
Net cash provided by (used in):					
Operating activities	$ (119,307)	$ 49,887	$ 217,057	$ (44,770)	$ 102,867
Continuing investing activities	300,985	295,697	(207,552)	(321,286)	67,844
Discontinued investing activities		(81)			(81)
Total investing activities	300,985	295,616	(207,552)	(321,286)	67,763
Financing activities	(181,678)	(345,499)	(9,505)	366,056	(170,626)
Net change in cash and cash equivalents		4			4
Cash and cash equivalents, beginning of period		164			164
Cash and cash equivalents, end of period	$	$ 168	$	$	$ 168

Table of Contents

NOTE 20 QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2013:				
Revenue	$ 580,128	$ 557,870	$ 560,939	$ 407,912
Costs and expenses	(581,918)	(582,369)	(548,866)	(410,871)
Equity income (loss) in joint ventures	(4,422)	(1,882)	(472)	2,040
Goodwill impairment loss	(43,866)			
Loss on asset disposition			(1,519)	
Loss on early extinguishment of debt			(19)	(26,582)
Income tax benefit	1,406	817	28	9
Net income (loss)	(48,672)	(25,564)	10,091	(27,492)
Income attributable to non-controlling interests	(2,282)	(1,514)	(1,810)	(1,369)
Preferred unit imputed dividend effect	(11,378)	(11,378)	(6,729)	
Preferred unit dividends in kind	(9,170)	(9,072)	(5,341)	
Net loss attributable to common limited partners and the General Partner	(71,502)	(47,528)	(3,789)	(28,861)
Net loss attributable to common limited partners per unit basic and diluted(5)(6)	$ (0.94)	$ (0.66)	$ (0.11)	$ (0.48)

(1) Net income includes a $15.4 million non-cash derivative loss.
(2) Net income includes a $23.6 million non-cash derivative loss.
(3) Net income includes a $24.3 million non-cash derivative gain.
(4) Net income includes a $13.7 million non-cash derivative loss.
(5) For the fourth, third, second, and first quarters of the year ended December 31, 2013, approximately 1,476,000, 1,455,000, 967,000, and 1,055,000 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.
(6) For the fourth, third, and second quarters of the year ended December 31, 2013, approximately 13,709,000, 13,518,000, and 9,013,000 weighted average Class D Preferred Units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit as the impact of the conversion would have been anti-dilutive.

Table of Contents

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2012:				
Revenue	$ 352,052	$ 277,568	$ 324,114	$ 292,286
Costs and expenses	(360,871)	(285,346)	(251,180)	(286,711)
Equity income in joint venture	2,088	1,422	1,917	896
Income tax expense	(176)			
Net income (loss)	(6,907)	(6,356)	74,851	6,471
Income attributable to non-controlling interests	(1,902)	(1,511)	(1,061)	(1,536)
Net income (loss) attributable to common limited partners and the General Partner	(8,809)	(7,867)	73,790	4,935
Net income (loss) attributable to common limited partners per unit basic and diluted(5)	$ (0.22)	$ (0.17)	$ 1.30	$ 0.06

(1) Net income includes an $8.3 million non-cash derivative loss.
(2) Net income includes a $22.5 million non-cash derivative loss.
(3) Net income includes a $64.7 million non-cash derivative gain.
(4) Net income includes a $10.7 million non-cash derivative loss.
(5) For the fourth and third quarter of the year ended December 31, 2012, approximately 1,022,000 and 964,000 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.

NOTE 21 SUBSEQUENT EVENTS

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its 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 Note 5). Based on this declaration, the Partnership also issued 274,785 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended December 31, 2013.

Table of Contents

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

ITEM 9B. OTHER INFORMATION

The description of the potential cash awards to our NEOs that appears under Item11: Executive Compensation Compensation Discussion and Analysis Determination of 2013 Compensation Amounts Annual Incentives is incorporated herein by reference.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our General Partner s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2013, our disclosure controls and procedures were effective at the reasonable assurance level.

Management s Report on Internal Control over Financial Reporting

The management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including our General Partner s Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 1992 Internal Control Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

159

Based on our evaluation under the 1992 COSO framework, management concluded that internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2013. Grant Thornton LLP, an independent registered public accounting firm and auditors of our consolidated financial statements, has issued its report on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2013, which is included herein.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited the internal control over financial reporting of Atlas Pipeline Partners, L.P. (a Delaware limited partnership) and subsidiaries (the Partnership) as of December 31, 2013, based on criteria established in the 1992 *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2013, and our report dated February 20, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 20, 2014

161

Table of Contents

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our General Partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us. Our General Partner will be liable, as general partner, for all our debts to the extent not paid, except to the extent that indebtedness or other obligations incurred by us are specifically with recourse only to our assets. Whenever possible, our General Partner intends to make any of our indebtedness or other obligations with recourse only to our assets.

As set forth in our Partnership Governance Guidelines and in accordance with NYSE listing standards, the non-management members of our General Partner s managing board meet in executive session regularly without management. The managing board member who presides at these meetings rotates at each meeting. The purpose of these executive sessions is to promote open and candid discussion among the non-management board members. Interested parties wishing to communicate directly with the non-management members may contact the chairman of the audit committee, Martin Rudolph, at P.O. Box 769, Ardmore, Pennsylvania 19003.

The independent board members comprise all the members of the managing board s conflicts committee, audit committee, environmental health and safety committee and compensation committee. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest to determine if the resolution of the conflict proposed by our General Partner is fair and reasonable to us, or as contemplated by our related party transaction policy. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls. Our audit committee has assumed the duties of our risk oversight committee and assists in evaluating, monitoring and addressing various risks that face us. The environmental, health and safety committee monitors our practices and performance, and makes recommendations, with respect to environmental, health and safety matters. The compensation committee acts in coordination with the compensation committee of Atlas Energy, L.P. (ATLS) in evaluating the compensation paid or payable to our General Partner s Chief Executive Officer and other named executive officers of our General Partner. Our compensation committee reviews compensation paid or payable under individual employment agreements, our executive compensation and bonus programs, our director compensation arrangements and our long-term incentive and other compensation and benefit plans.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operation. Rather, all of the personnel that manage and operate our business are employed by ATLS. Some of the officers of our General Partner may spend a substantial amount of time managing the business and affairs of ATLS and its affiliates, and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Table of Contents

Managing Board Members and Executive Officers of Our General Partner

The following table sets forth information with respect to the executive officers and managing board members of our General Partner:

Name	Age	Position with the General Partner	Year in which service began
Edward E. Cohen	75	Executive Chairman of the Managing Board	1999
Jonathan Z. Cohen	43	Executive Vice Chairman of the Managing Board	1999
Eugene N. Dubay	65	Chief Executive Officer and Managing Board Member	2008
Patrick J. McDonie	53	President and Chief Operating Officer	2012
Robert W. Karlovich, III	36	Chief Financial Officer	2009
Gerald R. Shrader	54	Chief Legal Officer and Secretary	2009
Tony C. Banks	59	Managing Board Member	1999
Curtis D. Clifford	71	Managing Board Member	2004
Gayle P. W. Jackson	67	Managing Board Member	2011
Martin Rudolph	67	Managing Board Member	2005
Michael L. Staines	64	Managing Board Member	1999

Edward E. Cohen has been the Executive Chairman of the managing board of our General Partner since its formation in 1999. Mr. Cohen was the Chief Executive Officer of our General Partner since its formation in 1999 through January 2009. Mr. Cohen has been the Chief Executive Officer and President of Atlas Energy GP, LLC (formerly known as Atlas Pipeline Holdings, GP, LLC) (Atlas Energy, GP) the general partner of ATLS since February 2011 and before that he served as Chairman of the Board from its formation in January 2006 until February 2011. Mr. Cohen served as Chief Executive Officer of ATLS from its formation until February 2009. Mr. Cohen also was the Chairman of the Board and Chief Executive Officer of Atlas Energy, Inc. (AEI) from its organization in 2000, until its consummation with Chevron Corporation in February 2011 (the Chevron Merger), and also served as its President from 2000 to October 2009 when Atlas Energy Resources, LLC (Atlas Energy Resources) became its wholly-owned subsidiary following its merger transaction. Mr. Cohen has served as Chairman of the Board of Atlas Resource Partners GP, LLC since February 2012. Mr. Cohen was the Chairman of the Board and Chief Executive Officer of Atlas Energy Resources and its manager, Atlas Energy Management, Inc. from their formation in June 2006, until the consummation of the Chevron Merger in February 2011. In addition, Mr. Cohen has been Chairman of the Board of Directors of Resource America, Inc. (a publicly-traded specialized asset management company) since 1990 and was its Chief Executive Officer from 1988 until 2004, and President from 2000 until 2003; Chairman of the Board of Resource Capital Corp. (a publicly-traded real estate investment trust) since its formation in September 2005 until November 2009 and currently serves on its board; and Chairman of the Board of Brandywine Construction & Management, Inc. (a property management company) since 1994. Mr. Cohen is the father of Jonathan Z. Cohen. Mr. Cohen has been active in the energy business for over 30 years. Mr. Cohen s strong financial and energy industry experience, along with his deep knowledge of the company resulting from his long tenure with the company, enables Mr. Cohen to provide valuable perspectives on many issues facing the company. Mr. Cohen s service on the managing board of our General Partner creates an important link between management and the managing board and provides the company with decisive and effective leadership. Mr. Cohen s extensive experience in founding, operating and managing

public and private companies of varying size and complexity enables him to provide valuable expertise to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen brings to the managing board the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country. These diverse experiences have enabled Mr. Cohen to bring unique perspectives to the managing board, particularly with respect to business management, financial markets and financing transactions and corporate governance issues.

Jonathan Z. Cohen has been Executive Vice Chairman of the managing board of our General Partner since our formation in 1999. Mr. Cohen has been the Executive Chairman of the Board of Atlas Energy, GP, the general partner of ATLS, since January 2012. Before that, he served as its Chairman from February 2011 to January 2012 and as Vice Chairman from its formation in January 2006 until February 2011. Mr. Cohen also was the Vice Chairman of the Board of AEI from its organization in 2000, until the consummation of the Chevron Merger in February 2011. Mr. Cohen has served as the Vice Chairman of the Board of Atlas Resource Partners GP, LLC since February 2012. Mr. Cohen was the Vice Chairman of the Board of Atlas Energy Resources and Atlas Energy Management from their formation in June 2006, until the consummation of the Chevron Merger in February 2011. Mr. Cohen has been a senior officer of Resource America, Inc. (a publicly-traded specialized asset management company) since 1998, serving as the Chief Executive Officer since 2004, President since 2003 and a director since 2002. Mr. Cohen has been Chief Executive Officer, President and a director of Resource Capital Corp. (a publicly-traded real estate investment trust) since 2005. Mr. Cohen is a son of Edward E. Cohen. Mr. Cohen s extensive knowledge of the company resulting from his long length of service with the company, as well as his strong financial and industry experience, allow him to contribute valuable perspectives on many issues facing the company. Mr. Cohen s service on the managing board of our General Partner creates an important link between management and the managing board and provides the company with decisive and effective leadership. Mr. Cohen s involvement with public and private entities of varying size, complexity and focus and raising debt and equity for such entities provides him with extensive experience and contacts that are valuable to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen s financial, business, operational and energy experience, as well as the experience he has accumulated through his activities as a financier and investor, adds strategic vision to our General Partner s managing board to assist with our growth, operations and development. Mr. Cohen is able to draw upon these diverse experiences to provide guidance and leadership with respect to exploration and production operations, capital markets and corporate finance transactions and corporate governance issues.

Eugene N. Dubay has been Chief Executive Officer of our General Partner since January 2009 and served as President from January 2009 until October 2013. Mr. Dubay has served as a member of the managing board of our General Partner since October 2008, where he served as an independent member until his appointment as President and Chief Executive Officer. Mr. Dubay was the Chief Executive Officer, President and a director of ATLS from February 2009 until February 2011, and now serves as Senior Vice President of Midstream Operations. Mr. Dubay has been the President of Atlas Pipeline Mid-Continent LLC, our wholly-owned subsidiary, since January 2009. Mr. Dubay was the Chief Operating Officer of Continental Energy Systems LLC, the parent of SEMCO Energy, from 2002 to January 2009. Mr. Dubay has also held positions with ONEOK, Inc. and Southern Union Company and has over 20 years experience in midstream assets and utilities operations, strategic acquisitions, regulatory affairs and finance. Mr. Dubay is a certified public accountant and a graduate of the U.S. Naval Academy. Throughout his career, Mr. Dubay has held positions of increasing responsibility in the energy industry. In these positions, Mr. Dubay has been responsible for developing and implementing strategic plans including, as applicable, regulatory strategies. This long-range approach is important to the Board s development of our strategic plans. The Board also benefits from Mr. Dubay s management and operational experience, as well as his strong leadership. This combined experience served as the basis for Mr. Dubay s appointment as a director.

165

Table of Contents

Patrick J. McDonie has been President of our General Partner since October 2013 and Chief Operating Officer of our General Partner since July 2012. Mr. McDonie served as a Senior Vice President of our General Partner from July 2012 until October 2013. Prior to that, from May 2008 to July 2012, Mr. McDonie was the President of ONEOK Energy Services Company, a natural gas transportation, storage, supplier and marketing company. Before becoming President of ONEOK Energy Services Company, Mr. McDonie was its Senior Vice President of Origination and New Business Development from 2005 to 2008. Before that, from 1997 to 2000, Mr. McDonie was Director of Trading and then, from 2000 to 2005, Vice President of Trading, for ONEOK Gas Marketing Company.

Robert W. Karlovich, III has been the Chief Financial Officer of our General Partner since October 2011 and the Chief Accounting Officer of our General Partner since November 2009. Mr. Karlovich was also the Chief Accounting Officer of Atlas Energy GP from November 2009 until March 2011. Before that, he was the Controller of Atlas Pipeline Mid-Continent LLC since September 2006. Mr. Karlovich was the Controller for Syntroleum Corporation, a publicly-traded energy company, from April 2005 until September 2006, and Accounting Manager from February 2004. Mr. Karlovich also worked as a public accountant with Arthur Andersen LLP and Grant Thornton LLP where he served numerous public clients and energy companies. Mr. Karlovich is a certified public accountant.

Gerald R. Shrader has been the Chief Legal Officer and Secretary of our General Partner since October 2009. Mr. Shrader has also been the General Counsel and a Senior Vice President of Atlas Pipeline Mid-Continent LLC since August 2007 and was the Chief Legal Officer and Secretary of Atlas Energy GP from October 2009 through February 2011. From January 2006 through July 2007, Mr. Shrader was an Assistant General Counsel with CMS Enterprises Company, a subsidiary of CMS Energy Corporation, a publicly-traded energy company. Prior to that time, Mr. Shrader worked both for publicly-traded energy companies and in private practice, including the provision of legal services to private and publicly-traded energy companies.

Tony C. Banks is the founder and has been President and Chief Executive Officer since August 2012 of Star Energy Partners, LLC, a retail provider of electricity, natural gas and energy related products and services to residential and business customers in competitive markets throughout the U.S. Prior to that, from February 2011 to August 2012, Mr. Banks was Vice President of Competitive Market Policies of FirstEnergy Solutions Corp., a subsidiary of FirstEnergy Corporation, a public utility, and from October 2009 to February 2011, he served as its Vice President of Product and Market Development. From March 2007 to October 2009, Mr. Banks served as Vice President of Business Development, Performance & Management for FirstEnergy Corporation and from December 2005 to February 2007, Mr. Banks was its Vice President of Business Development. Mr. Banks first joined FirstEnergy Solutions, Corp., in August 2004 as Director of Marketing and in August 2005 became Vice President of Sales & Marketing. Before joining FirstEnergy, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the board of Optiron Corporation, an energy technology subsidiary of AEI. In addition, Mr. Banks served as President of our General Partner during 2000 and served as Chief Executive Officer and President of AEI from 1998 through 2000. In Mr. Banks role at AEI, he gained experience in natural gas exploration and production. He also served on the board of directors of TRM Corporation, a provider of ATM services, from October 2006 to April 2008. Mr. Banks is a noted expert in competitive retail energy markets, having provided written and oral testimony in several states on regulatory policy and utility tariff filings and, over the past 9 years, has been engaged with electricity generation, pricing and marketing (including involvement with renewable energy standards and compliance with emission requirements for electricity generators). The Board benefits from Mr. Banks knowledge of natural gas production and energy markets, including natural gas markets.

Table of Contents

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. From January 2001 through June 2010, he worked for UtiliTech, Inc., utility and telecommunications specialists in West Lawn, PA, where he advised and assisted commercial and industrial gas consumers nationwide with procurement activities and utility rate options. In July 2010, he transitioned to a consultant role for UtiliTech and continues in that role for Edge Insights, successor to UtiliTech effective January2014. He is also President and Chairman of the board of Amity Manor, Inc., a non-profit corporation, which he founded in 1988 to develop housing for low-income elderly using tax credit financing. Mr. Clifford is a Life Member of the American Society of Civil Engineers and is a registered professional engineer in Pennsylvania. Mr. Clifford has 47 years experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and utility rates. Mr. Clifford s experience and working knowledge of the gas industry provide valuable strategic insight into opportunities for our services, as well as compliance responsibilities with respect to our operations.

Gayle P.W. Jackson, PhD has been President and CEO of Energy Global, Inc., a consulting firm, which specializes in corporate development, diversification and government relations strategies for energy companies, since 2004. From 2001 to 2004, Dr. Jackson served as Managing Director of FE Clean Energy Group, a global private equity management firm that invests in energy companies and projects in Asia, Central and Eastern Europe and Latin America. From 1985 to 2001, Dr. Jackson was President of Gayle P.W. Jackson, Inc., a consulting firm that advised energy companies on corporate development and diversification strategies and also advised national and international governmental institutions on energy policy. From 1985 to 1995, she was also Chief of Staff of the International Energy Agency s Coal Industry Advisory Board. Dr. Jackson served as Deputy Chairman of the Federal Reserve Bank of St. Louis in 2004-05 and was a member of the Federal Reserve Bank Board from 2000 to 2005. She is a member of the Board of Directors of Ameren Corporation, a publicly-traded public utility holding company, as well as its Nominating and Corporate Governance Committee and Nuclear Oversight and Environmental Committee. She is also a member of the Advisory Panel of Climate Change Capital Private Equity, a London-based private equity buyout fund manager that invests in clean technology companies. Dr. Jackson served as an independent director of AEI from July 2009 until the consummation of the Chevron Merger in 2011. Dr. Jackson served as an independent member of the managing board of our General Partner from March 2005 until July 2009. The Board benefits from Dr. Jackson s experience in the energy industry, including her previous service as a director of our General Partner, as well as AEI. Dr. Jackson s strong background in finance assists the Board in evaluating investment alternatives and the Partnership s capital needs.

Martin Rudolph has been the Trustee of the AHP Settlement Trust, a billion dollar trust established to process litigation claims, since 2005. Before that, Mr. Rudolph was a director of tax planning, research and compliance for RSM McGladrey, Inc., a business services firm from 2001 to 2005. From 1990 to 2001, he was the Managing Partner of Rudolph, Palitz LLC, which merged with McGladrey & Pullen LLP, a national accounting firm, where he was the Managing Partner of the Philadelphia economic unit. In that position, he oversaw all of the professional services rendered by the firm, which included the audit of public and privately-held companies. Mr. Rudolph brings a strong accounting background to our board and serves as the chair of our audit committee. Mr. Rudolph has over 40 years of experience as an independent certified public accountant, which has been critical in developing and overseeing our internal audit program. Additionally, Mr. Rudolph s vast finance and accounting experience enable him to provide guidance with respect to accounting matters, as well as evaluating financing alternatives.

Michael L. Staines has been the President of Pine Tree Energy Partners, LLC, an energy consulting firm since October 2009. From 2000 to January 2009, Mr. Staines was our President and Chief Operating Officer. Mr. Staines was an Executive Vice President of AEI from its formation in 2000 until July 2009. Mr. Staines was Senior Vice President of Resource America, Inc. from 1989 to 2004 and

167

served as a director from 1989 through 2000 and Secretary from 1989 through 1998. Mr. Staines is a member of the Independent Oil and Gas Association of Pennsylvania and the Independent Petroleum Association of America. Mr. Staines brings extensive knowledge regarding oil and gas production in Pennsylvania, which complemented our development and participation in Laurel Mountain. In addition, Mr. Staines has historical knowledge of our company and operations and was involved in our strategic development. The Board benefits from these combined experiences coupled with Mr. Staines extensive knowledge of the energy industry.

We have assembled a managing board of directors of our General Partner comprised of individuals who bring diverse but complementary skills and experience to oversee our business. Our managing board members collectively have a strong background in energy, finance, accounting and management. Based upon the experience and attributes of the managing board members discussed herein, the managing board of our General Partner determined that each of the managing board members should serve on the managing board of our General Partner.

Edward E. Cohen serves as the Executive Chairman of the managing board of our General Partner and Eugene N. Dubay serves as the Chief Executive Officer of our General Partner. The managing board of our General Partner believes that oversight of management is an important component of an effective managing board. The managing board believes that the most effective leadership structure at the present time is for separation of the chairman of the managing board from the chief executive officer positions. The managing board believes that because the chief executive officer is ultimately responsible for our day-to-day operations and for executing our strategy, we are best served to have a separate chairman of the managing board as it allows for proper oversight, guidance and accountability. The chief executive officer contacts the chairman of the managing board on a regular basis and provides status updates of operations during these discussions. Additionally, our Chief Executive Officer and the Executive Chairman of the managing board, along with the Executive Vice Chairman of the managing board, serve together as our executive committee.

Risk Oversight

Our audit committee assumes the duties of our risk oversight. In its risk oversight role, our audit committee reports to the managing board periodically on its activities and is generally responsible for overseeing the guidelines and policies that govern our enterprise risk management program. Our audit committee provides oversight for a management-level risk management committee comprised of members of senior management, which is tasked with monitoring material enterprise risks, overseeing our framework for management of risks and reporting any significant changes or updates to our key risks to the audit committee and our CEO. Our audit committee coordinates and exchanges information with our environmental, health and safety committee with respect to the monitoring and assessment of the risks facing us on environmental, health and safety matters. Additionally, individuals who oversee risk management in liquidity and credit areas, along with environmental, litigation and other operational areas, periodically provide reports to the managing board during regular board meetings. In addition, our managing board has access to our management at all levels to discuss any matters of interest, including those related to risk.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and managing board members of our General Partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports.

168

Table of Contents

Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required, we believe that all of the officers and managing board members of our General Partner and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements during fiscal year 2013.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our General Partner does not receive any management fee or other compensation for its services apart from its general partner and incentive distributions. We reimburse our General Partner and its affiliates, including ATLS, for all expenses incurred on our behalf. These expenses include the costs of employee, officer and managing board member compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us in any reasonable manner determined by our General Partner, in its sole discretion. Our General Partner allocates the costs of employee and officer compensation and benefits based upon the amount of time spent on our business by those employees and officers. In addition to those expenses directly attributable to our business (such as the compensation and benefits for officers and employees that devote all of their time to our business and specific awards under our incentive compensation programs), in 2013 we reimbursed our General Partner and its affiliates $5.0 million for an allocated share of compensation and benefits for officers and employees that do not devote all of their time to our business.

Information Concerning the Audit Committee

The managing board of our General Partner has a standing audit committee. All the members of the audit committee are independent directors as defined by NYSE rules. The members of the audit committee are Mr. Rudolph, Mr. Banks and Dr. Jackson, with Mr. Rudolph acting as the chairperson. The managing board has determined that Mr. Rudolph is an audit committee financial expert, as defined by SEC rules. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls. Our audit committee has assumed the duties of our risk oversight committee and assists in evaluating, monitoring and addressing various risks that face us.

Compensation Committee Interlocks and Insider Participation

The compensation committee of the managing board of our general partner consists of Messrs. Banks, Clifford and Rudolph, with Mr. Banks acting as the chairperson.

Mr. Banks was the Chairman of the Board of Optiron Corporation, which was a subsidiary of AEI until 2002. In addition, Mr. Banks served as President of our General Partner during 2000. He was Chief Executive Officer and President of AEI from 1998 through 2000. At our October 2006 managing board meeting, the managing board initially determined Mr. Banks to be an independent board member pursuant to NYSE listing standards and Rule 10A-3(b) promulgated under the Securities Exchange Act of 1934. This determination was re-affirmed at our January 2014 Board meeting. No executive officer of our General Partner is a director or executive officer of any entity in which an independent managing board member is a director or executive officer.

Table of Contents

Code of Business Conduct and Ethics, Partnership Governance Guidelines and Committee Charters

We have adopted a code of business conduct and ethics that applies to the principal executive officer, principal financial officer and principal accounting officer of our General Partner, as well as to persons performing services for us generally. We have also adopted Partnership Governance Guidelines and charters for our audit committee, compensation committee and environmental health and safety committee. We will make a printed copy of our code of ethics, our Partnership Governance Guidelines and our committee charters available to any unitholder who so requests. Requests for print copies may be directed to us as follows: Atlas Pipeline Partners, L.P., Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011, Attention: Secretary. Each of the code of business conduct and ethics, the Partnership Governance Guidelines and the committee charters are posted, and any waivers we grant to our business conduct and ethics will be posted, on our website at www.atlaspipeline.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We are required to provide information regarding the compensation program in place as of December 31, 2013, for our General Partner s Chief Executive Officer (CEO), Chief Financial Officer (CFO) and the three other most highly-compensated executive officers. In this report, we refer to our General Partner s CEO, CFO and the other three most highly-compensated executive officers as our named executive officers or NEOs. This section should be read in conjunction with the detailed tables and narrative descriptions below.

Our NEOs, as well as the other people who work for us, are employees of ATLS. Therefore, we do not directly provide cash compensation to our NEOs. ATLS allocates the cash compensation of our NEOs between activities on behalf of us and activities on behalf of it and its other affiliates based upon an estimate of the time spent by such persons on activities for us and for it and its affiliates. In addition, ATLS adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits which represents their estimated incremental costs. Because Messrs. Dubay, Karlovich and McDonie devote all their time to us, all their cash compensation costs are allocated to us. Our compensation committee is responsible for designing our compensation objectives and methodology and determining compensation payable to those officers and employees who devote time to our business. Our compensation committee also administers our benefit plans and programs. Our compensation committee provides its determinations to the ATLS compensation committee, and the ATLS compensation committee retains the right to accept, reject or modify the determinations with respect to the NEOs that serve both companies. ATLS also administers its own benefit plans, some costs of which are allocated to us. Our compensation committee communicates and coordinates with the ATLS compensation committee with respect to awards made under our incentive plans. We incur the costs associated with any awards that our compensation committee makes under our incentive programs (including awards to officers and employees that devote only a portion of their time to us). Our compensation committee is comprised solely of independent directors, consisting of Messrs. Banks, Clifford and Rudolph, with Mr. Banks acting as the chairperson.

Compensation Objectives

Our compensation committee believes our compensation program must support our business strategy, be competitive, and provide both significant rewards for outstanding performance and clear financial consequences for underperformance. It also believes a significant portion of the NEOs compensation should be at risk in the form of annual and long-term incentive awards that are made, if at all, based on individual and company accomplishment. Our compensation committee considers cost implications as well as our business needs (including the need to attract and retain qualified personnel to run our business) in the design of our compensation programs.

Table of Contents

Compensation Methodology

Our compensation committee generally establishes compensation amounts shortly after the close of our fiscal year. In the case of base salaries, it approves the amounts to be paid for the new fiscal year. In the case of annual incentive awards, the compensation committee approves or recommends the amount of awards based on the then concluded fiscal year. We typically make determinations with respect to salary adjustments and make annual incentive awards in February, although the compensation committee has the discretion to make salary adjustments and equity awards throughout the year. Some of our NEOs also receive stock-based awards from ATLS.

Each year, the Executive Chairman of the managing board of our General Partner, who also serves as the CEO and President of ATLS general partner, provides our compensation committee with key elements of our financial and operating performance for the preceding year, as well as the individual performance of our NEOs. The Chairman makes recommendations to our compensation committee regarding the salary and annual incentive compensation for each NEO. The Chairman may also, either annually or at other times during the year, make recommendations with respect to long-term incentive awards. The Chairman, at our compensation committee s request, may attend compensation committee meetings to provide insight into our company s performance, as well as the performance of other comparable companies in the same industry. For the 2013 compensation determinations, the CEO of our General Partner also provided the compensation committee with his assessment of our operating performance for the year, as well as the performance of our NEOs, and made recommendations regarding salary and annual incentive compensation that were consistent with those of the Executive Chairman.

Role of Compensation Consultant

In late 2012, our compensation committee engaged Meridian Compensation Partners, LLC (Meridian), an independent compensation consulting firm, to evaluate the competitiveness of our executive and board compensation programs. For executive compensation, the evaluation included an analysis of 2012 base salaries, target bonuses and equity awards of executive officers that devote all of their time to us. Meridian was not asked to conduct an analysis with respect to executive officers (including NEOs) that do not devote all of their time to our business. For board compensation, the evaluation consisted of an analysis of average annual board compensation consisting of a combination of: (i) annual board retainer and/or meeting fees; (ii) annual equity awards; and (iii) committee chairperson retainer and/or meeting fees. Meridian also advised our compensation committee with respect to compensation practices generally.

In order to assist the compensation committee in assessing the competitiveness of our executive and outside director compensation programs, Meridian provided market data for a peer group consisting of similarly-sized publicly-traded master limited partnerships engaged in the gathering and processing business. Meridian proposed a group of eighteen companies, all of which publicly disclosed comparable outside director compensation programs, and twelve which disclosed comprehensive executive compensation programs. Compensation data was compiled from publicly available information, as reported for the 2011 fiscal year, for the following companies:

Peer Group for Executive and Board Compensation

Markwest Energy Partners LP

Regency Energy Partners LP

Targa Resources Partners LP

Access Midstream Partners LP

PVR Partners LP

Copano Energy LLC

DCP Midstream Partners LP

Eagle Rock Energy Partners LP

Crosstex Energy Inc.

Crestwood Midstream Partners LP

Summit Midstream Partners LP

Blueknight Energy Partners LP

Also included in the Peer Group for Board Compensation:

Martin Midstream Partners LP

Western Gas Partners LP

Rose Rock Midstream LP

Holly Energy Partners LP

Tesoro Logistics LP

EQT Midstream Partners LP

Our compensation committee accepted Meridian s proposed peer group and plans to monitor the peer group to ensure that it remains aligned with our business activities. Meridian also made use of a broad-based survey regarding compensation at energy companies generally, as well as pipeline companies. Meridian used the survey principally for the analysis of management level employees in our organization, because the peer group analysis did not generate adequate compensation information other than for our top four executives.

Meridian found that:

- the 2012 base salaries for Messrs. Dubay, McDonie and Karlovich were generally aligned with the 75th percentile of our peer group; and

- the long-term incentive awards for 2012, standing alone, were substantially in excess of typical annual awards made by our peers, while the combined beneficial ownership and outstanding equity awards in favor of our NEOs that were covered by Meridian s report (after taking the 2012 equity awards into account) compared favorably to approximately the 50th percentile of our peer group.

Meridian did not express an opinion on actual bonus compensation, indicating that deviations from target bonus compensation are often made based on company and individual performance. The compensation committee intends to obtain updates of the peer group analysis every other year. Although our compensation committee consulted with Meridian throughout the year regarding general compensation trends and related matters, the company did not request that Meridian update the peer group data or provide other material advice in making compensation decisions for 2013.

Table of Contents

The members of the compensation committee are, after inquiry with Meridian, not aware of any affiliation or relationship between Meridian or any of its employees and any of our or ATLS management, nor do we or they retain Meridian to provide other services. This was a critical factor in our compensation committee s selection of Meridian to provide consulting services. In addition, we have a code of business conduct and ethics, as well as a related party transaction policy, which governs potential conflicts of interest. Our directors and officers also complete questionnaires, which would allow us to review whether there are any potential conflicts as a result of personal or business relationships with Meridian.

Elements of our Compensation Program

Our executive officer compensation package includes a combination of cash and long-term incentive compensation. Cash compensation is comprised of base salary plus short-term cash incentive (bonus) compensation. Long-term incentives consist of a variety of equity awards. Both the annual and long-term incentives may be performance-based.

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contributed to our success. Base salaries are not intended to compensate individuals for extraordinary performance or for above average company performance.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of our NEO s compensation to our performance, as well as their individual performance. Generally, the higher the level of responsibility of the executive, the greater is the incentive component of that executive s target compensation. Although the compensation committee may recommend awards of performance-based bonuses, our annual incentive compensation is generally discretionary in nature. Our annual incentive compensation has typically been paid cash.

Unless otherwise provided in their respective employment agreements, our compensation committee may, based on recommendations of management, annually establish target bonuses for members of our management team. For 2013, the compensation committee established target bonus amounts, as a percentage of base salary, as follows:

Name	2013 Target Bonus
Eugene N. Dubay	100%
Patrick J. McDonie	100%
Robert W. Karlovich, III	65%

The target bonuses may be decreased, increased or not paid at all, in the discretion of the compensation committee, based on quantitative and qualitative factors, as determined from time-to-time by the compensation committee. Generally, these factors are intended to align short-term incentives with our financial performance and the resulting benefits to our unitholders, as well as recognize individual performance in contributing to these goals.

Long-Term Incentives

The compensation committee believes our long-term success depends upon aligning our executives and unitholders interests. To support this objective, we provide our executives with various means to become significant equity holders, including awards under our 2004 Long-Term Incentive Plan

(the 2004 LTIP) and our 2010 Long-Term Incentive Plan (the 2010 LTIP), which we collectively refer to as our Plans. The compensation committee recommends grants of equity awards in the form of options and/or phantom units. The phantom units under our Plans generally vest over four years (subject, in the appropriate case, to accelerated vesting as outlined under the description of our plans). There are no option awards currently outstanding under our Plans.

Our NEOs are also eligible to receive awards under the ATLS long-term incentive plans, which we refer to as the ATLS Plans and under the long-term incentive plan adopted by Atlas Resource Partners, L.P., an ATLS subsidiary (NYSE: ARP) (ARP).

ATLS Performance-Based Bonuses

ATLS has an Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, to award bonuses for achievement of predetermined performance objectives during a 12-month performance period, generally ATLS s and our fiscal year. Awards under the Senior Executive Plan may be paid in cash or in a combination of cash and time-vesting equity of ATLS. A portion of the cash amount awarded to our participating NEOs is allocated to us.

During 2013, the ATLS compensation committee approved 2013 bonus awards to be paid from a bonus pool equal to a maximum of 18.3% of ATLS s distributable cash flow. One of two goals for 2013 had to be met before any bonuses would be paid:

- at least 80% of the average distributable cash flow allocable to ATLS for the past three years; and
- at least 80% of the average production volumes (which for ATLS means production volumes and for us means gathered volumes) for the past three years.

The goals are set early in the year, but actual awards are ultimately determined by the ATLS compensation committee s year-end evaluation that also evaluates other factors as set forth below. While the ATLS compensation committee has the discretion to make awards even if one of the goals is not met, it does not anticipate doing so absent exceptionally rare circumstances justifying the payment of a bonus. In the event that distributable cash flow includes any capital transaction gains in excess of $50 million, then only 10% of that excess is included in the bonus pool. Distributable cash flow means the sum of (i) cash available for distribution by ATLS, including the distributable cash flow of any of its subsidiaries (including our company), regardless of whether such cash is actually distributed, plus (ii) to the extent not otherwise included in distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iii) to the extent not otherwise included in distributable cash flow, any loss on the sale of securities, including securities of a subsidiary. A return of ATLS s capital investment in a subsidiary was not intended to be included and, accordingly, if distributable cash flow included proceeds from the sale of all or substantially all of the assets of a subsidiary, the amount of such proceeds to be included in distributable cash flow would be reduced by ATLS s basis in the subsidiary.

The maximum award, expressed as a percentage of ATLS s estimated 2013 distributable cash flow, for each of our NEO participants was as follows: Mr. E. Cohen 6.22%; Mr. J. Cohen 5.49%; and Mr. Dubay 2.20%. Mr. Dubay s maximum award amount will be reduced by any incentive compensation we pay to him, and the deducted amount may be available for allocation among the other participants in the Senior Executive Plan. Messrs. McDonie and Karlovich did not participate in the Senior Executive Plan in 2013.

Table of Contents

Pursuant to the terms of the Senior Executive Plan, the ATLS compensation committee has discretion to recommend reductions, but not increases, in maximum awards under the Senior Executive Plan. In making its decisions, the committee considers factors, including growth of reserves, growth in production, processing and intake of natural gas, total market and distribution return to ATLS s unitholders, and health and safety performance.

Post-Termination Compensation

ATLS entered into employment agreements with Messrs. E. Cohen, J. Cohen, and Dubay that, among other things, provide compensation upon termination of their employment by reason of death or disability, by ATLS without cause or by each of them for good reason. In addition, we (along with ATLS) entered into an employment agreement with Mr. McDonie that provides compensation in the event of his termination for similar reasons. See Employment Agreements and Potential Payments Upon Termination or Change of Control.

The rationale of ATLS compensation committee (and our compensation committee, with respect to Mr. McDonie) behind the design of the provisions for termination by the executive for good reason is as follows:

Determination of Triggering Events The ATLS compensation committee (and our compensation committee, with respect to Mr. McDonie) elected not to include a change of control of ATLS or us as a good reason triggering event and instead limited the triggering events to those (including after a change of control) where his position with ATLS or us, as the case may be, changes substantially and is essentially an involuntary termination.

Benefit Multiple The ATLS compensation committee determined the benefit multiple, that is, the cash severance amount based on each executive s salary and bonus, after consideration of comparable market practices provided to the committee by Mercer. Our compensation committee determined the benefit multiple during negotiations with Mr. McDonie based on the similar benefits provided by his previous employer. Our compensation committee believes the benefit multiple is consistent with terms generally available in our industry.

Perquisites

We provide limited perquisites to our NEOs at the discretion of our compensation committee. In 2013, these benefits were limited to providing a car allowance to Mr. McDonie and reimbursement of club membership dues for Mr. Karlovich.

Determination of 2013 Compensation Amounts

Base Salary

In February 2014, our compensation committee approved the base salaries for our NEOs as follows: Mr. Dubay $500,000, Mr. McDonie $390,000 and Mr. Karlovich $340,000. These amounts represent a 0%, 4.0% and 9.7% increase from the 2013 base salaries for Messrs. Dubay, McDonie and Karlovich , respectively. The salary adjustments were made by our compensation committee to recognize the high level of effort required by our executives to support our acquisition, financing and operational activities throughout the year.

Annual Incentives

In determining annual incentive awards for 2013, our compensation committee considered financial and operational performance for 2013, including the results and integration of our acquisitions undertaken during late 2012 and 2013. In particular, our compensation committee noted the substantial

175

efforts of our executives to identify, complete and integrate the Cardinal and TEAK acquisitions, which expanded our footprint into two new, highly desirable operating areas. The compensation committee also reflected on the substantial efforts required of our executives to identify and execute on desirable financing alternatives, including issuance of senior unsecured debt at historically low interest rates. The compensation committee also considered that the results of our acquisitions, for a variety of economic and competitive reasons, fell below expectations, particularly in terms of anticipated volume forecasts.

Recognizing the excellent work of our NEOs during 2013, but also recognizing that the performance of our recent acquisitions has not met initial projections, the compensation committee decided not to award cash bonuses for 2013.

For 2014, in order to motivate our NEOs to achieve the originally forecasted production volumes, the compensation committee decided to authorize the executive committee to make cash awards of $100,000 each to our NEOs if (i) our gathered volumes on operating assets initially included in our approved 2014 budget reach at least 1.8 billion cubic feet per day (Bcf/day), as averaged over a fiscal quarter, and (ii) the executive committee determines that cash flows are sufficient to pay the cash awards.

Long-Term Incentives

In July, 2013, our compensation committee made the following awards of phantom units to our NEOs: (1) Mr. E. Cohen   50,000 phantom units; (2) Mr. J. Cohen   50,000 phantom units; (3) Mr. Dubay   50,000 phantom units; (4) Mr. McDonie   30,000 phantom units and (5) Mr. Karlovich   20,000 phantom units. The awards will vest 25% on each anniversary of the grant. Our compensation committee determined that competition for experienced personnel, particularly from private equity firms, had substantially increased and that the awards were necessary to insure the continued services of our NEOs.

In February, 2014, our compensation committee made awards of our phantom units (with DERs) for similar reasons as follows: 50,000 phantom units to each of Messrs. E. Cohen, J. Cohen and Dubay, 20,000 phantom units to Mr. McDonie and 15,000 phantom units to Mr. Karlovich. The units will vest ratably over three years. Because these awards were made after 2013 year-end, they do not appear in the Summary Compensation table or the Grants of Plan-Based Awards table that follow, but will be reflected in the tables appearing in our 2014 annual report.

ATLS Performance-Based Bonuses

After the end of its 2013 fiscal year, the ATLS compensation committee considered incentive awards pursuant to the Senior Executive Plan based on the year s performance. The committee confirmed that ATLS had achieved both of the performance goals established for the Senior Executive Plan. The committee recognized the continued strong performance and decided to make awards that were generally commensurate with overall awards that had been granted in 2011 and 2012, and therefore, did not grant awards at the maximum level for any of the NEOs.

In view of evolving corporate governance standards, the ATLS compensation committee decided to continue to move its annual incentive compensation from a largely cash-based system to a substantially equity-based bonus system. To that end, the committee determined to grant awards that were substantially in the form of equity, such that no cash component of the bonuses awarded to the NEOs exceeded 32%. The cash portion of the awards allocated to us was as follows: Mr. E. Cohen $420,000 and Mr. J. Cohen $420,000. In light of the Phantom units awarded to Mr. Dubay in February 2014, Mr. Dubay elected not to receive a separate award under the Senior Executive Plan.

The following tables set forth the compensation allocation to us for fiscal years 2013, 2012 and 2011 for our General Partner s CEO, CFO and each of our other most highly compensated executive officers whose allocated aggregate salary and bonus (including amounts of salary and bonus foregone to receive non-cash compensation) exceeded $100,000. As required by SEC guidance, the tables also disclose awards under the ATLS Plans.

Table of Contents

SUMMARY COMPENSATION TABLE

me and Principal Position	Year	Salary	Bonus	Stock Awards(1)	Option Awards(2)	Non-Equity Incentive Plan Compensation(3)	All Other Compensation	Total
gene N. Dubay,	2013	$ 500,000	$	$ 1,975,500	$	$	$ 388,638 (4)	$ 2,864,13
EO	2012	500,000	1,500,000	3,498,000			440,792	5,938,79
	2011	500,000		1,778,400	993,000	1,000,000	5,136,128	9,407,52
bert W. Karlovich,	2013	309,077		1,280,700			174,614 (5)	1,764,39
, CFO	2012	286,000	585,000	699,600			163,996	1,734,59
	2011	220,192	350,000	1,628,300	99,300		69,188	2,366,98
ward E. Cohen,	2013	350,000		1,975,500		420,000	272,991 (7)	3,018,49
ecutive Chairman	2012	98,577	1,000,000	3,498,000		302,500	206,097	5,105,17
the Managing Board(6)	2011	101,423				525,000	25,650	652,07
nathan Z. Cohen,	2013	245,000		1,975,500		420,000	272,000 (8)	2,912,50
ecutive Vice Chairman	2012	82,000	1,000,000	3,498,000		351,000	198,930	5,129,93
the Managing Board (6)	2011	72,115				450,000	21,375	543,49
trick J. McDonie,	2013	374,039		2,166,300			252,250 (9)	2,792,58
esident and COO	2012	156,154	600,000	2,997,000			93,617	3,846,77
	2011							

(1) The amounts reflect the grant date fair value of the phantom units under our Plans and the ATLS Plans. The grant date fair value was determined based on the market value on the grant date of our units and ATLS units. See Item 8. Financial Statements and Supplementary Data Note 11 for further discussion regarding assumptions made in valuation of fair value.

(2) The amounts in this column reflect the grant date fair value of options awarded under the ATLS Plans.

(3) The amounts in this column reflect payments under the ATLS Senior Executive Plan, which were allocated to us.

(4) Includes payments on DERs of $131,388 with respect to the phantom units awarded under the ATLS Plans and $257,250 with respect to the phantom units awarded under our Plans.

(5) Includes payments on DERs of $25,423 with respect to the phantom units awarded under the ATLS Plans and $141,850 with respect to the phantom units awarded under our Plans.

(6) Amounts for Messrs. E. Cohen and J. Cohen reflect only the portion of compensation allocated to us.

(7) Includes payments on DERs of $272,000 with respect to the phantom units awarded under our Plans and our allocated portion of tax, title and insurance premiums for Mr. E. Cohen s automobile.

(8) Includes payments on DERs of $272,000 with respect to the phantom units awarded under our Plans.

(9) Includes payments on DERs of $48,200 with respect to the phantom units awarded under the ATLS Plans and $195,050 with respect to the phantom units awarded under our Plans and car allowance of $9,000.

Table of Contents

GRANTS OF PLAN-BASED AWARDS

Name	Estimated Possible Payments Under Non-Equity Incentive Plan Awards[1] Threshold ($)	Target ($)	Maximum ($)	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Unit Awards[2]
Eugene N. Dubay	N/A	N/A	N/A	7/10/2013	50,000 (3)	$ 1,975,500
Robert W. Karlovich, III	N/A	N/A	N/A	7/10/2013	20,000 (4)	790,200
				7/16/2013	10,000 (5)	490,500
Edward E. Cohen	N/A	N/A	21,500,000	7/10/2013	50,000 (3)	1,975,500
				2/4/2013	47,281 (6)	1,799,988
Jonathan Z. Cohen	N/A	N/A	19,000,000	7/10/2013	50,000 (3)	1,975,500
				2/4/2013	42,027 (7)	1,599,968
Patrick J. McDonie	N/A	N/A	N/A	7/10/2013	30,000 (8)	1,185,300
				7/16/2013	20,000 (9)	981,000

(1) Represents performance-based bonuses under ATLS Senior Executive Plan, as discussed under Compensation Discussion and Analysis Elements of our Compensation Program ATLS Performance-Based Bonuses
(2) The grant date fair value was calculated in accordance with FASB ASC Topic 718.
(3) Represents phantom units granted under our 2010 LTIP, which vest as follows: 07/10/14 12,500; 07/10/15 12,500; 07/10/16 12,500; and 07/10/17 12,500.
(4) Represents phantom units granted under our 2010 LTIP, which vest as follows: 07/10/14 5,000; 07/10/15 5,000; 07/10/16 5,000; and 07/10/17 5,000.
(5) Represents phantom units granted under the ATLS 2010 Plan, which vest as follows: 07/16/16 2,500; 07/16/17 7,500.
(6) Represents phantom units granted under the ATLS 2006 Plan, which vest as follows: 02/04/14 15,760; 02/04/16 15,760; 02/04/17 15,761. Phantom units granted to Mr. E. Cohen under the ATLS Plans are not allocated to us and are not included in the Summary Compensation Table.
(7) Represents phantom units granted under the ATLS 2006 Plan, which vest as follows: 02/04/14 14,009; 02/04/16 14,009; 02/04/17 14,009. Phantom units granted to Mr. J. Cohen under the ATLS Plans are not allocated to us and are not included in the Summary Compensation Table.
(8) Represents phantom units granted under our 2010 LTIP, which vest as follows: 07/10/14 7,500; 07/10/15 7,500; 07/10/16 7,500; and 07/10/17 7,500.
(9) Represents phantom units granted under the ATLS 2010 Plan, which vest as follows: 07/16/16 5,000; 07/16/17 15,000.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Terms Used

Good reason is defined in the following employment agreements as:

a material reduction in base salary;

a demotion from his position;

a material reduction in duties, and for Messrs. E. Cohen, J. Cohen, and Dubay, it being deemed such a material reduction if ATLS ceases to be a public company unless it becomes a subsidiary of a public company and,

in the case of Mr. E. Cohen, he becomes the chief executive officer of the public parent immediately following the applicable transaction;

in the case of Mr. J. Cohen, he becomes an executive officer of the public parent with responsibilities substantially equivalent to his previous position immediately following the applicable transaction;

in the case of Mr. Dubay, the CEO or the Chairman of ATLS s general partner s board is not its CEO or the CEO of ATLS or the acquiring entity;

the executive is required to relocate to a location more than 35 miles from the executive s previous location, or 50 miles from Tulsa, Oklahoma in the case of Mr. McDonie;

in the case of Mr. E. Cohen and Mr. J. Cohen, ceasing to be elected to ATLS s board; or

in the case of Messrs. E. Cohen, J. Cohen and Dubay, any material breach of the agreement.

Cause is defined in Mr. E. Cohen and Mr. J. Cohen s employment agreements as:

Mr. Cohen is convicted of a felony, or any crime involving fraud or embezzlement;

Mr. Cohen intentionally and continually fails to perform his reasonably assigned duties (other than as a result of disability), which failure is materially and demonstrably detrimental to ATLS and has continued for 30 days after written notice signed by a majority of the independent directors of ATLS s general partner; or

Mr. Cohen is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

Cause is defined in Mr. Dubay and Mr. McDonie s employment agreements as:

in the case of Mr. Dubay, executive has committed any demonstrable and material fraud;

in the case of Mr. Dubay, illegal or gross misconduct that is willful and results in damage to our business or reputation, and in the case of Mr. McDonie, willful misconduct which cases material harm to us or our affiliates or their business reputations, including due to adverse publicity;

in the case of Mr. Dubay, executive is charged with a felony, and in the case of Mr. McDonie, the commission of a felony or crime of moral turpitude;

in the case of Mr. Dubay, failure to substantially perform his duties (other than as a result of disability) after written demand and a reasonable opportunity to cure, and in the case of Mr. McDonie, willful and continued failure to perform material duties (other than as a result of a disability);

in the case of Mr. McDonie, the commission of any act of malfeasance or wrongdoing against our company or affiliates;

in the case of Mr. Dubay, failure to follow reasonable written instructions which are consistent with his duties, and in the case of Mr. McDonie, material breach of any of our policies or procedures; or

in the case of Mr. McDonie, material breach of his obligations under any agreement entered into with us or our affiliates.

Edward E. Cohen

Effective May 16, 2011, ATLS entered into an employment agreement with Mr. Cohen to secure his service as President and Chief Executive Officer. The agreement has a term of three years, which automatically renews daily, unless terminated before the expiration of the term pursuant to the termination provisions of the agreement. As discussed above under Compensation Discussion and Analysis, ATLS allocates a portion of Mr. Cohen s compensation cost to us based on an estimate of the time spent by Mr. Cohen on our activities. In addition, ATLS adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits.

The agreement provides for an initial annual base salary of $700,000, which may be increased at the discretion of the board of directors of ATLS general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided by ATLS for its senior level executives generally. During the term of the agreement, ATLS must maintain a term life insurance policy on Mr. Cohen s life, which provides a death benefit of $3.0 million, which can be assumed by Mr. Cohen upon a termination of employment.

The agreement provides the following benefits in the event of a termination of employment:

Upon termination of employment due to death, all equity awards held by Mr. Cohen accelerate and vest in full upon the later of the termination of employment or six months after the date of grant of the awards (Acceleration of Equity Vesting), and Mr. Cohen s estate is entitled to receive, in addition to payment of all accrued and unpaid amounts of base salary, vacation, business expenses and other benefits (Accrued Obligations), a pro-rata bonus for the year of termination, based on the actual bonus that would have been earned had the termination of employment not occurred, determined and paid consistent with past practice (the Pro-Rata Bonus).

ATLS may terminate Mr. Cohen s employment if he has been unable to perform the material duties of his employment for 180 days in any 12-month period because of physical or mental injury or illness, but ATLS is required to pay his base salary until it acts to terminate his employment. Upon termination of employment due to disability, Mr. Cohen will receive the Accrued Obligations, all amounts payable under ATLS long-term disability plans, three years continuation of group term life and health insurance benefits (or, alternatively, ATLS may elect to pay executive cash in lieu of such coverage in an amount equal to three years healthcare coverage at COBRA rates and the premiums ATLS would have paid during the three-year period for such life insurance) (such coverage, the Continued Benefits), Acceleration of Equity Vesting, and the Pro-Rata Bonus.

Upon termination of employment by ATLS without cause or by Mr. Cohen for good reason, Mr. Cohen will be entitled to either (i) if he does not execute and not revoke a release of claims against ATLS, payment of the Accrued Obligations, or (ii), in addition to payment of the Accrued Obligations, if he executes and does not revoke a release of claims against ATLS, (A) a lump-sum cash payment in an amount equal to three times his average compensation (which, assuming a termination date of December 31, 2013, is defined as the sum of (1) his annualized base salary in effect immediately before the termination of employment plus (2) the average of the bonuses earned for 2011 and 2012, (B) Continued Benefits, (C) the Pro-Rata Bonus, and (D) Acceleration of Equity Vesting.

Upon a termination by ATLS for cause or by Mr. Cohen without good reason, he is entitled to receive payment of the Accrued Obligations.

In connection with a change of control, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen will be reduced such that the total payments to the executive, which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G safe harbor amount if he would be in a better after-tax position as a result of such reduction.

We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on more than one year of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the applicable period. The following table provides an estimate of the value of the benefits to Mr. Cohen, which would have been allocated to us if a termination event had occurred as of December 31, 2013.

Reason for Termination	**Lump Sum Severance Payment**	**Benefits(1)**	**Accelerated Vesting of Equity Awards(2)**
Death	$ 2,100,000	$	$ 4,381,250
Disability	2,100,000	20,169	4,381,250
Termination by us without cause or by Mr. Cohen for good reason	10,774,831(3)	20,169	4,381,250
Change of control	9,094,831(3)	20,169	4,381,250

(1) Dental and medical benefits were calculated using 2013 COBRA rates.
(2) Represents the value of unvested unit awards granted under our 2010 LTIP disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Jonathan Z. Cohen

Effective May 16, 2011, ATLS entered into an employment agreement with Mr. Cohen to secure his service as Chairman of the Board. The agreement has a term of three years, which automatically renews daily, unless terminated before the expiration of the term pursuant to the termination provisions of the agreement. As discussed above under Compensation Discussion and Analysis, ATLS allocates a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. In addition, ATLS adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits.

Table of Contents

The agreement provides for an initial annual base salary of $500,000, which may be increased at the discretion of the board of directors of ATLS general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans of ATLS and receive perquisites and reimbursement of business expenses, in each case as provided by ATLS for our senior level executives generally. During the term of the agreement, ATLS must maintain a term life insurance policy on Mr. Cohen s life, which provides a death benefit of $2 million, which can be assumed by Mr. Cohen upon a termination of employment.

The agreement provides the same benefits in the event of a termination of employment as described above in Mr. E. Cohen s employment agreement summary.

In connection with a change of control, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen will be reduced such that the total payments to the executive, which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G safe harbor amount if he would be in a better after-tax position as a result of such reduction.

We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on more than one year of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the applicable period. The following table provides an estimate of the value of the benefits to Mr. Cohen, which would have been allocated to us if a termination event had occurred as of December 31, 2013.

Reason for Termination	Lump Sum Severance Payment	Benefits[(1)]	Accelerated Vesting of Equity Awards[(2)]
Death	$ 1,925,000	$	$ 4,381,250
Disability	1,925,000	29,278	4,381,250
Termination by us without cause or by Mr. Cohen for good reason	9,891,071[(3)]	29,278	4,381,250
Change of control	8,386,071[(3)]	29,278	4,381,250

(1) Dental and medical benefits were calculated using 2013 COBRA rates.

(2) Represents the value of unvested unit awards granted under our 2010 LTIP disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.

(3) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Eugene N. Dubay

On November 4, 2011, ATLS entered into an employment agreement with Mr. Dubay. Under the agreement, Mr. Dubay has the title of Senior Vice-President of the Midstream Operations division of Atlas Energy, GP. The agreement has an initial term of two years, which automatically renews for successive one-year terms unless earlier terminated pursuant to the termination provisions of the agreement.

The agreement provides for an initial annual base salary of $500,000, and Mr. Dubay is entitled to participate in any short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided by ATLS for its senior executives generally.

Table of Contents

The agreement provides the following benefits in the event of a termination of Mr. Dubay s employment:

- Upon a termination by ATLS for cause or by Mr. Dubay without good reason, he is entitled to receive payment of accrued but unpaid base salary and (to the extent required to be paid under company policy) amounts of accrued but unpaid vacation, in each case through the date of termination (together, the Accrued Obligations).

- Upon a termination of employment due to death or disability (defined as Mr. Dubay being physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and the determination by ATLS general partner s board of directors, in good faith based upon medical evidence, that he is unable to perform his duties), all equity awards held by Mr. Dubay accelerate and vest in full upon such termination (Acceleration of Equity Vesting), and Mr. Dubay or his estate is entitled to receive, in addition to payment of all Accrued Obligations, an amount equal to the cash bonus earned by him for the prior fiscal year multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which his termination occurs through the date of termination, and the denominator of which is the total number of days in such fiscal year (the Pro-Rata Bonus).

- Upon a termination of employment by ATLS without cause (which, for purposes of the Acceleration of Equity Vesting includes a non-renewal of the agreement) or by Mr. Dubay for good reason, he is entitled to either:

  - if he does not timely execute (or revokes) a release of claims against ATLS, payment of the Accrued Obligations; or

  - in addition to payment of the Accrued Obligations, if he timely executes and does not revoke a release of claims against ATLS:

    - monthly cash severance installments each in an amount equal to one-twelfth of the sum of his then-current (i) annual base salary and (ii) the annual cash incentive bonus earned by him in respect of the fiscal year preceding the fiscal year in which his termination of employment occurs for the portion of the employment term remaining after the date of termination, payable for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred,

    - healthcare continuation at active employee rates for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred, a prorated amount in respect of the cash bonus granted to him in respect of the fiscal year in which his termination of employment occurs based on actual performance for such year, calculated as the product of (x) the amount which would have been earned in respect of the award based on actual performance measured at the end of such fiscal year and (y) a fraction, the numerator of which is the number of days in such fiscal year through the date of termination, and the denominator of which is the total number of days in such fiscal year, paid in a lump sum in cash on the date payment would otherwise be made had he remained employed by ATLS, and

Acceleration of Equity Vesting.

Table of Contents

In connection with a change of control of ATLS, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Dubay will be reduced such that the total payments to him, which are subject to Section 280G are no greater than the Section 280G safe harbor amount if he would be in a better after-tax position as a result of such reduction.

We anticipate that all lump sum termination amounts paid to Mr. Dubay would be allocated to us. The following table provides an estimate of the value of the benefits to Mr. Dubay if a termination event had occurred as of December 31, 2013.

Reason for Termination	Lump Sum Severance Payment	Benefits[(1)]	Accelerated Vesting of Equity Awards[(2)]
Death or Disability	$ 1,500,000	$	$ 11,330,246
Termination by us without cause or by Mr. Dubay for good reason	1,666,667[(3)]	38,325	11,330,246

(1) Dental and medical benefits were calculated using 2013 COBRA rates for 22 months, which assumes renewal of Mr. Dubay s employment agreement upon expiration of the initial term in November 2013.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2013. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Calculated based on Mr. Dubay s current base salary plus the applicable bonus. Payments would be made in monthly installments for the remaining term of Mr. Dubay s employment agreement.

Patrick J. McDonie

On July 3, 2012, ATLS entered into an employment agreement with Mr. McDonie to secure his service as Senior Vice President and Chief Operating Officer of our General Partner. The agreement has a term of two years, commencing as of the effective date of Mr. McDonie s employment and automatically renews for one year renewal terms unless ATLS gives prior written notice of non-renewal.

The agreement provides for an annual base salary of $350,000 (subject to adjustment at the discretion of ATLS and our compensation committees), established Mr. McDonie s target bonus at 100% of base salary and granted a one-time award of 70,000 of our phantom units and 20,000 phantom units of ATLS. Our phantom units vest 25% per year over 4 years and the ATLS phantom units vest 25% on the third anniversary of the grant and 75% on the fourth anniversary of the grant. Upon vesting, the phantom units automatically convert to common units of the respective issuer. Mr. McDonie is also eligible for: (i) discretionary bonus compensation, which was guaranteed for fiscal 2012 at $200,000; (ii) car allowance and country club dues; (iii) eligibility to receive subsequent grants of equity compensation; and (iv) participation in all employee benefit plans in effect during his employment.

The agreement provides the following benefits in the event of a termination of Mr. McDonie s employment:

Upon termination of employment by ATLS without cause or by Mr. McDonie for good reason, Mr. McDonie will receive his base salary paid through the end of the then-current term; (ii) pro-rated cash bonus for the year of termination, based on actual performance for the year; (iii) 100% accelerated vesting of his equity awards; and (iv) monthly severance pay in an amount equal to 1/12 of (x) his annual base salary and (y) the annual amount of cash bonus paid to Mr. McDonie for the fiscal year prior to his year of termination. If Mr. McDonie s employment is terminated without cause or Mr. McDonie terminates his employment for good reason during the initial term, the monthly severance payments will be made for two years. If Mr. McDonie s employment is terminated due to a non-renewal for the first renewal period, the monthly severance payments will be made for one year and, if he is terminated thereafter, the monthly severance payments will be made for the unexpired term, as then in effect.

Upon termination of employment due to death or disability, Mr. McDonie will receive (i) his base salary paid through the termination date; (ii) pro-rated cash bonus for the year of termination, based on the bonus paid for the prior; and (iii) 100% accelerated vesting of his equity awards.

Upon termination of employment by ATLS for cause or by Mr. McDonie for any reason other than good reason in the first two years of employment, Mr. McDonie is subject to a one year non-competition covenant and will receive his base salary paid through the date of termination.

We anticipate that all lump sum termination amounts paid to Mr. McDonie would be allocated to us. The following table provides an estimate of the value of the benefits to Mr. McDonie if a termination event had occurred as of December 31, 2013.

Reason for Termination	**Lump Sum Severance Payment**	**Accelerated Vesting of Equity Awards(1)**
Death or Disability	$ 856,731	$ 4,765,625
Termination by us without cause or by Mr. McDonie for good reason	756,731(2)	4,765,625

(1) Represents the value of unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2012.

(2) Calculated based on Mr. McDonie s current base salary plus the applicable bonus. Payments would be made in monthly installments for the remaining term of Mr. McDonie s employment agreement.

Additional Change of Control Payments

Awards granted under our Long-Term Incentive Plans and the ATLS Plans vest following a change of control and/or the occurrence of certain other events, as described below. If these awards had terminated on December 31, 2013, in addition to the accelerated vesting of awards received by Messrs. E. Cohen, J. Cohen, Dubay, and McDonie; Mr. Karlovich would have received accelerated vesting of awards valued at $3,280,651.

Our Long-Term Incentive Plans

Our Plans provide incentive awards to officers, employees and non-employee managers of our General Partner and officers and employees of our General Partner s affiliates, consultants and joint venture partners who perform services for us or in furtherance of our business. Our Plans are administered by our General Partner s managing board or the board of an affiliate designated by it (the Committee). Our compensation committee has been designated to serve as the Committee. Under the Plans, the Committee may, among other types of awards available under the 2010 LTIP, make awards of either phantom units or options covering an aggregate of 435,000 common units under the 2004 LTIP and 3,000,000 common units under the 2010 LTIP.

A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. In addition, the Committee may grant a participant the right, which we refer to as a DER, to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions we make on a common unit during the period the phantom unit is outstanding.

An option entitles the grantee to purchase our common units at an exercise price determined by the Committee, which may be less than, equal to or more than the fair market value of our common units on the date of grant. The Committee will also have discretion to determine how the exercise price may be paid.

Prior to October 2010, each non-employee board member of our General Partner received an annual grant of a maximum of 500 phantom units, which upon vesting, entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The 2004 LTIP was amended by the managing board of our General Partner in February 2010 to increase the pool of phantom units that may be awarded to non-employee board members from 10,000 to 15,000. The total amount of common units that can be awarded under the 2004 Plan was not amended. The Committee will determine the vesting period for phantom units and the exercise period for options. Under the 2004 LTIP, phantom units awarded to non-employee board members will generally vest over a 4-year period at the rate of 25% per year. Under the 2004 LTIP, awards will vest upon a change of control, which is defined as follows:

Atlas Pipeline Partners GP ceasing to be our General Partner;

a merger, consolidation, share exchange, division or other reorganization or transaction of us, our General Partner or a direct or indirect parent of our General Partner with any entity, other than a transaction, which would result in the voting securities of us, our General Partner or its parent, as appropriate, outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 60% of the combined voting power immediately after such transaction of the surviving entity s outstanding securities or, in the case of a division, the outstanding securities of each entity resulting from the division;

the equity holders of us or a direct or indirect parent of our General Partner approve a plan of complete, liquidation or winding-up or an agreement for the sale or disposition (in one transaction or a series of transactions) of all or substantially all of our or such parent s assets; or

during any period of 24 consecutive months, individuals who at the beginning of such period constituted the board of directors of Atlas Pipeline GP or a direct or indirect parent of our General Partner (including for this purpose any new director whose election or nomination for election or appointment was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of such period) cease for any reason to constitute at least a majority of the board or, in the case of a spinoff of the parent, if Edward E. Cohen and Jonathan Z. Cohen cease to be directors of the parent.

Under the 2010 LTIP, unless otherwise specified in the award agreement(s), awards will vest upon a change of control, which (unless otherwise defined in the award) is defined as follows:

Atlas Pipeline GP or an affiliate ceases to be our general partner;

consummation of a merger, consolidation, share exchange, division or other reorganization or transaction of us, our General Partner or any affiliate that is a direct or indirect parent of our General Partner with any entity, other than a transaction, which would result in the voting securities of us or our General Partner, as appropriate, outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 60% of the combined voting power immediately after such transaction of the surviving entity s outstanding securities or, in the case of a division, the outstanding securities of each entity resulting from the division;

our equity holders, our General Partner or any affiliate that is a direct or indirect parent of our General Partner approve a plan of complete liquidation or winding-up of us;

consummation of a sale or disposition (in one transaction or a series of transactions) of all or substantially all of the assets of APL or any affiliate that is a direct or indirect parent of our General Partner to an entity that is not an affiliate of our General Partner or us; or

during any period of 24 consecutive months, individuals who at the beginning of such period constituted the Board or the board of directors of an affiliate that is a direct or indirect parent of our General Partner (including for this purpose any new director whose election or nomination for election or appointment was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of such period) cease for any reason to constitute at least a majority of the Board or other board of directors, as applicable.

The Chevron Merger did not trigger the change of control provisions discussed above. If a grantee terminates employment, the grantee s award will be automatically forfeited unless the Committee provides otherwise. However, the award will automatically vest if the reason for the termination is the participant s death or disability. Common units to be delivered upon vesting of phantom units or upon exercise of options may be newly issued units, units acquired in the open market or from any of our affiliates, or any combination of these sources at the discretion of the Committee. If we issue new common units upon vesting of the phantom units or upon the exercise of options, the total number of common units outstanding will increase. We filed a registration statement with the SEC in order to permit participants to publicly re-sell any common units received by them under the Plans.

The Committee may terminate the Plans at any time with respect to any of the common units for which it has not made a grant. In addition, the Committee may amend the Plans from time to time, including, subject to applicable law or the rules of the principal securities exchange on which our common units are traded, increasing the number of common units with respect to which it may grant awards, provided that, without the participant s consent, no change may be made in any outstanding grant that would materially impair the rights of the participant. NYSE rules require us to obtain unitholder approval for all material amendments to the Plans, including amendments to increase the number of common units issuable thereunder.

Upon a change in control, as defined in each Plan, all unvested awards held by non-employee managers will vest, except as otherwise specified in the award agreement(s). Upon a change of control, as defined in the 2004 LTIP, all unvested awards held by employees will vest. In the case of awards held by employees under the 2010 LTIP, upon termination of employment without cause , as defined in the 2010 LTIP, or upon other circumstances specified in the employee s applicable award agreement(s), in any case following a change in control, any unvested award will vest and, in the case of options, become exercisable.

187

Table of Contents

ATLS Plans

The ATLS 2006 Long-Term Incentive Plan (the ATLS 2006 Plan) and the ATLS 2010 Long-Term Incentive Plan (the ATLS 2010 Plan and collectively with the 2006 ATLS Plan, the ATLS Plans) provides equity incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners who perform services for ATLS. The ATLS Plans are administered by the board of ATLS general partner or the board of an affiliate appointed by ATLS board (the ATLS Committee). The ATLS Committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 ATLS common limited partner units for the ATLS 2006 Plan and an aggregate of 5,300,000 ATLS common limited partner units for the ATLS 2010 Plan. In February, 2011, ATLS amended the ATLS 2006 Plan to provide that outstanding awards granted under ATLS 2006 Plan did not vest in connection with the Chevron Merger pursuant to the terms and conditions of the ATLS 2006 Plan.

Partnership Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Non-employee directors receive an annual grant of phantom units having a market value of $125,000, which, upon vesting, entitle the grantee to receive the equivalent number of ATLS common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the ATLS Committee may grant a DER. The ATLS Committee determines the vesting period for phantom units. Phantom units granted under the 2006 ATLS Plan generally vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant, except non-employee director grants vest 25% per year.

Partnership Unit Options. A unit option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of a common unit as determined by the ATLS Committee on the date of grant of the option. The ATLS Committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Unit options granted under the 2006 ATLS Plan generally will vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant.

Partnership Restricted Units. Under the ATLS 2010 Plan, a restricted unit is a common unit issued that entitles a participant to receive it upon vesting of the restricted unit. Prior to or upon grant of an award of restricted units, the ATLS Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both.

Upon a change in control, as defined in the ATLS 2010 Plan, all unvested awards held by directors will immediately vest in full. In the case of awards held by eligible employees, upon the eligible employee s termination of employment without cause , as defined in the ATLS Plans, or upon any other type of termination specified in the eligible employee s applicable award agreement(s), in any case following a change in control, any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option.

The following tables disclose outstanding awards and awards vested and exercised under our Plans as well as under the ATLS Plans.

Table of Contents

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Option Exercise Price	Option Expiration Date	Number of Units that have not Vested	Market Value of Units that have not Vested[1]
Eugene N. Dubay		108,765[2]	$ 20.44	3/25/2021	87,012[3]	$ 4,076,512
					125,000[4]	4,381,250
Robert W. Karlovich, III		10,876[5]	20.44	3/25/2021	20,876[6]	978,041
					57,500[7]	2,015,375
Edward E. Cohen	543,825[8]		20.75	11/10/2016		
		761,355[9]	20.44	3/25/2021	373,576[10]	17,502,036
					125,000[4]	4,381,250
	87,500[11]	262,500[12]	24.67	5/15/2022	112,500[13]	2,304,000
Jonathan Z. Cohen	217,530[8]		20.75	11/10/2016		
		543,825[14]	20.44	3/25/2021	313,939[15]	14,708,042
					125,000[4]	4,381,250
	87,500[11]	262,500[12]	24.67	5/15/2022	112,500[13]	2,304,000
Patrick J. McDonie			N/A	N/A	40,000[16]	1,874,000
					82,500[17]	2,891,625

(1) Based on closing market price of our common units on December 31, 2013 of $35.05 and price of ATLS common units on December 31, 2013 of $46.85.
(2) Represents options to purchase ATLS units, which vest as follows: 03/25/14 27,191; 03/25/15 81,574.
(3) Represents ATLS phantom units, which vest as follows: 03/25/14 21,753; and 03/25/15 65,259.
(4) Represents our phantom units, which vest as follows: 04/26/14 25,000; 07/10/14 12,500; 04/26/15 25,000; 07/10/15 12,500; 04/26/16 25,000 07/10/16 12,500; and 07/10/17 12,500.
(5) Represents options to purchase ATLS units, which vest as follows: 03/25/14 2,719; 03/25/15 8,157.
(6) Represents ATLS phantom units, which vest as follows: 03/25/14 2,719; 03/25/15 8,157; 07/16/16 2,500; and 07/16/17 7,500.
(7) Represents our phantom units, which vest as follows: 04/26/14 5,000; 06/22/14 2,500; 07/10/14 5,000; 11/04/14 10,000; 04/26/15 5,000; 07/10/15 5,000; 11/04/15 10,000; 04/26/16 5,000; 07/10/16 5,000; and 07/10/17 5,000.
(8) Represents options to purchase ATLS units.
(9) Represents options to purchase ATLS units, which vest as follows: 03/25/14 190,338; 03/25/15 571,017.
(10) Represents ATLS phantom units, which vest as follows: 02/04/14 15,760; 03/25/14 81,573; 02/04/15 15,760; 03/25/15 244,722; and 02/04/16 15,761.
(11) Represents options to purchase ARP units.
(12) Represents options to purchase ARP units, which vest as follows: 05/15/14 87,500; 05/15/15 87,500; and 05/15/16 87,500.
(13) Represents ARP phantom units, which vest as follows: 05/15/14 37,500; 05/15/15 37,500; and 05/15/16 37,500.

(14) Represents options to purchase ATLS units, which vest as follows: 03/25/14 135,956; 03/25/15 407,869.
(15) Represents ATLS phantom units, which vest as follows: 02/04/14 14,009; 03/25/14 67,978; 02/04/15 14,009; 03/25/15 203,934; and 02/04/16 14,009.
(16) Represents ATLS phantom units, which vest as follows: 07/20/15 5,000; 07/16/16 5,000; 07/20/16 15,000; and 07/16/17 15,000.
(17) Represents our phantom units, which vest as follows: 07/16/14 7,500; 07/20/14 17,500; 07/16/15 7,500; 07/20/15 17,500; 07/16/16 7,500; 07/20/16 17,500 and 07/16/17 7,500.

Table of Contents

2013 OPTION EXERCISES AND STOCK VESTED TABLE

	Unit Awards	
Name	Number of Units Acquired on Vesting	Value Realized on Vesting ($)(1)
Eugene N. Dubay	25,000 (2)	$ 895,000
Robert W. Karlovich, III	17,500 (2)	656,475
Edward E. Cohen	25,000 (2)	895,000
	37,500 (3)	909,375
Jonathan Z. Cohen	25,000 (2)	895,000
	37,500 (3)	909,375
Patrick J. McDonie	17,500 (2)	679,525

(1) Value realized on vesting is based upon market price on date of vesting.
(2) Represents our common units.
(3) Represents ARP s common units.

Director Compensation

2013 DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash	Stock Awards	All Other Compensation(1)	Total
Tony C. Banks	$ 75,000	$ 74,983(2)	$ 11,350	$ 161,333
Curtis D. Clifford	75,000	74,997(3)	9,978	159,975
Gayle P.W. Jackson	75,000	74,976(4)	10,054	160,030
Martin Rudolph	80,000	74,974(5)	10,819	165,793
Michael Staines	65,000	74,977(6)	9,623	149,600

(1) Represents payments on DERs for phantom units.
(2) Represents 1,531 and 738 phantom units having a grant date fair value of $32.65 and $33.87, respectively, granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 2/11/14 382; 2/20/14 184; 02/11/15 382; 2/20/15 184; 2/11/16 382 2/20/16 184; 2/11/17 385; and 2/20/17 186.
(3) Represents 1,971 phantom units having a grant date fair value of $38.05 granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 5/10/14 492; 5/10/15 492; 5/10/16 492 and 5/10/17 495.
(4) Represents 1,500 and 738 phantom units having a grant date fair value of $33.32 and $33.87, respectively, granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 2/18/14 375; 2/20/14 184; 02/11/15 375; 2/20/15 184; 2/11/16 375 2/20/16 184; 2/11/17 375; and 2/20/17 186.
(5)

Represents 2,297 phantom units having a grant date fair value of $32.64 granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 3/17/14 574; 3/17/15 574; 3/17/16 574 and 3/17/17 575.

(6) Represents 1,922 phantom units having a grant date fair value of $39.01 under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 7/01/14 480; 7/01/15 480; 7/01/16 480 and 7/01/17 482.

Our General Partner did not pay additional remuneration to officers or employees of ATLS who also served as managing board members. In February 2013, the ATLS nominating and governance committee approved, effective as of January 1, 2013, annual retainers for non-employee board members comprised of $65,000 in cash and an annual grant of phantom units with DERs issued under our Plans having a fair market value of $75,000. In addition, chairpersons of the compensation committee, conflicts committee and environmental health and safety committee each receive an additional retainer of $10,000 and the chair of the audit committee receives an additional retainer of $15,000. Effective October 1, 2013, the ATLS nominating and governance committee increased the annual retainer for the chair of our audit committee to $25,000.

Our General Partner reimburses each non-employee managing board member for out-of-pocket expenses in connection with attending meetings of the board or committees. We reimburse our General Partner for these expenses and indemnify our General Partner s managing board members for actions associated with serving as directors to the extent permitted under Delaware law.

Compensation Committee Report

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis with management and, based upon its review and discussions, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in this annual report on Form 10-K for the year ended December 31, 2013.

This report has been provided by the compensation committee of the Board of Directors of Atlas Pipeline Partners GP, LLC.

Tony A. Banks, Chair

Curtis D. Clifford

Martin Rudolph

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth the number and percentage of shares of common stock owned, as of February 18, 2014 by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding common units, (b) each of the members of the managing board of our General Partner, (c) each of the executive officers named in the Summary Compensation Table in Item 11, and (d) all of the executive officers and board members as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person. The address of our General Partner, its executive officers and managing board members is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011.

Table of Contents

Name of Beneficial Owner	Common Unit Amounts and Nature of Beneficial Ownership	Percent of Class
Named Executive Officers and Members of the Managing Board		
Eugene N. Dubay	104,300(1)	*
Edward E. Cohen	114,100(2)	*
Jonathan Z. Cohen	78,527(3)	*
Patrick J. McDonie	11,500	*
Robert W. Karlovich, III	42,287(4)	*
Tony C. Banks	4,585	*
Curtis D. Clifford	3,662	*
Gayle P. W. Jackson	4,814(5)	*
Martin Rudolph	6,184(6)	*
Michael L. Staines	13,353	*
Executive officers and Managing Board Members as a group (11 persons)	441,608	*
Other Owners of More than 5% of Outstanding Units		
Atlas Energy, L.P.	5,754,253(7)	7.1%
Leon G. Cooperman	7,858,773(8)	9.8%
FMR LLC.	4,073,205(9)	5.1%

* Less than 1%.

(1) Includes 76,125 units held in trust for the benefit of Mr. Dubay and 37,175 units held in trust for the benefit of Mr. Dubay s spouse.

(2) Includes 80,100 units held by a partnership, of which Mr. E. Cohen and his spouse are the sole limited partners and the sole shareholders, officers and directors of the corporate general partner.

(3) Includes 73,650 units held jointly with Mr. J. Cohen s spouse.

(4) Includes 250 units held in trust for the benefit of Mr. Karlovich s children.

(5) Includes 2,597 units held in trust for the benefit of Dr. Jackson.

(6) Includes 1,501 phantom units granted pursuant to our 2004 and 2010 LTIPs, which will vest into common units within 60 days; and 2,332 units held jointly with Mr. Rudolph s spouse.

(7) Includes 1,641,026 units held by our General Partner. ATLS disclaims beneficial ownership to such units.

(8) This information is based upon a Schedule 13G/A, which was filed with the SEC on February 3, 2014. The address for Mr. Cooperman is 11431 W. Palmetto Park Road, Boca Raton, FL 33431.

(9) This information is based upon a Schedule 13G/A, which was filed with the SEC on February 14, 2014. The address for FMR LLC is 245 Summer Street, Boston, MA 02210.

Equity Compensation Plan Information

The following table contains information about our 2004 LTIP as of December 31, 2013:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights** (a)	**Weighted-average exercise price of outstanding options, warrants and rights** (b)	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))** (c)
Equity compensation plans approved by security holders phantom units	45,732	n/a	
Equity compensation plans approved by security holders Total	45,732		6,409

192

Table of Contents

The following table contains information about our 2010 LTIP as of December 31, 2013:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights** (a)	**Weighted-average exercise price of outstanding options, warrants and rights** (b)	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))** (c)
Equity compensation plans approved by security holders phantom units	1,400,821	n/a	
Equity compensation plans approved by security holders Total	1,400,821		834,461

The following table contains information about the ATLS 2006 Plan as of December 31, 2013:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights** (a)	**Weighted-average exercise price of outstanding options, warrants and rights** (b)	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))** (c)
Equity compensation plans approved by security holders phantom units	234,940	n/a	
Equity compensation plans approved by security holders unit options	939,939	$ 20.94	
Equity compensation plans approved by security holders Total	1,174,879		763,476

The following table contains information about the ATLS 2010 Plan as of December 31, 2013:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights** (a)	**Weighted-average exercise price of outstanding options, warrants and rights** (b)	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))** (c)
Equity compensation plans approved by security holders phantom units	2,054,534	n/a	
Equity compensation plans approved by security holders unit options	2,452,412	$ 20.52	
Equity compensation plans approved by security holders Total	4,506,946		1,202,774

Table of Contents

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

We do not directly employ any persons to manage or operate our business. These functions are provided by our General Partner and employees of ATLS. Our General Partner does not receive a management fee in connection with its management of our operations, but we reimburse our General Partner and its affiliates for compensation and benefits related to ATLS employees who perform services for us, based upon an estimate of the time spent by such persons on our activities. Other indirect costs, such as rent for offices, are allocated to us by ATLS based on the number of its employees who devote substantially all of their time to our activities. Our partnership agreement provides that our General Partner will determine the costs and expenses that are allocable to us in any reasonable manner determined at its sole discretion. We reimbursed our General Partner and its affiliates $5.0 million for the year ended December 31, 2013 for compensation and benefits related to their employees. Our General Partner believes the method utilized in allocating costs to us is reasonable.

Effective as of April 30, 2009, our General Partner s conflicts committee adopted a written policy governing related party transactions. For purposes of this policy, a related party includes: (i) any executive officer, director or director nominee; (ii) any person known to be a beneficial owner of 5% or more of our common units; (iii) an immediate family member of any person included in clauses (i) and (ii) (which, by definition, includes, a person s spouse, parents and parents in law, step parents, children, children in law and stepchildren, siblings and brothers and sisters in law and anyone residing in the that person s home); and (iv) any firm, corporation or other entity in which any person included in clauses (i) through (iii) above is employed as an executive officer, is a director, partner, principal or occupies a similar position or in which that person owns a 5% or more beneficial interest. With certain exceptions outlined below, any transaction between us and a related party that is anticipated to exceed $120,000 in any calendar year must be approved, in advance, by the conflicts committee. If approval in advance is not feasible, the related party transaction must be ratified by the conflicts committee. In approving a related party transaction the conflicts committee will take into account, in addition to such other factors as the conflicts committee deems appropriate, the extent of the related party s interest in the transaction and whether the transaction is no less favorable to us than terms generally available to an unaffiliated third party under similar circumstances.

The following related party transactions are pre-approved under the policy: (i) employment of an executive officer to perform services on our behalf (or on behalf of one of our subsidiaries); (ii) compensation paid to directors for serving on the board of Atlas Pipeline GP or any committee thereof; (iii) transactions where the related party s interest arises solely as a holder of our common units and such interest is proportional to all other owners of common units or a transaction (e.g. participation in health plans) that are available to all employees generally; (iv) a transaction with another company where the related party is only an employee (and not an executive officer), director or beneficial owner of less than 10% of such company s shares and the aggregate amount involved does not exceed the greater of $1,000,000 or 2% of that firm s total annual revenues; and (v) any charitable contribution, grant or endowment by us or Atlas Pipeline GP to a charitable organization, foundation or university at which the related party s only relationship is as an employee (other than an executive officer) or director or similar capacity, if the aggregate amount involved does not exceed the greater of $5,000 or 2% of that organization s total receipts.

We compress and gather gas for Atlas Resource Partners, L.P. (NYSE: ARP) (ARP) on our gathering systems located in Tennessee. 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. We entered into an agreement to provide these services, which extends for the life of ARP s leases, in February 2008. We charged ARP approximately $0.3 million in compression and gathering fees for the year ended December 31, 2013.

Table of Contents

We agreed to provide design, procurement and construction management services for ARP with respect to a pipeline to be located in Lycoming County, Pennsylvania (the Lycoming Pipeline). We were reimbursed approximately $1.8 million by ARP for these services during the year ended December 31, 2013. The Lycoming Pipeline has been completed and we are not obligated to render additional services to ARP in connection with this project.

In connection with the TEAK Acquisition, we sold approximately 1.7 million of our Class D Preferred Units for approximately $50.0 million to Omega Capital and its affiliates, which collectively held more than 5% of our outstanding limited partnership units as of December 31, 2013. Sale of the Class D Preferred Units was made upon substantially the same terms as those for unrelated third parties that also purchased Class D Preferred Units in connection with the TEAK Acquisition and was approved in advance by the Conflicts Committee

The managing board of our General Partner has determined that Messrs. Curtis Clifford, Tony Banks, Martin Rudolph and Michael Staines and Dr. Gayle Jackson each satisfy the requirement for independence set out in Section 303A.02 of the rules of the New York Stock Exchange (the NYSE) including those set forth in Rule 10A-3(b)(1) of the Securities Exchange Act, and meet the definition of an independent member set forth in our Partnership Governance Guidelines. In making these determinations, the managing board reviewed information from each of these non-management board members concerning all their respective relationships with us and analyzed the materiality of those relationships.

Table of Contents

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ended December 31, 2013 and 2012 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2013	2012
Audit fees [(1)]	$ 1,531,750	$ 1,417,000
Tax fees [(2)]	93,778	91,080
All other fees		
Total aggregate fees billed	$ 1,625,528	$ 1,508,080

(1) Represents the aggregate fees recognized in 2013 and 2012 for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements, the review of financial statements included in Forms 10-Q and the review of registration statements and Forms 8-K.

(2) Represents the fees recognized in each 2013 and 2012 for professional services rendered by Grant Thornton LLP for tax compliance, tax advice, and tax planning.

Audit Committee Pre-Approval Policies and Procedures

Pursuant to its charter, the audit committee of the managing board of our General Partner is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. All of such services and fees were pre-approved during 2013 and 2012.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Financial Statements

The financial statements required by this Item 15(a)(1) are set forth in Item 8.

(2) Financial Statement Schedules

No schedules are required to be presented.

(3) Exhibits:

Exhibit No.	Description
2.1	Purchase and Sale agreement, dated as of April 16, 2013, among TEAK Midstream Holdings, LLC, TEAK Midstream, L.L.C. and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request[33]
3.1(a)	Certificate of Limited Partnership[1]
3.1(b)	Amendment to Certificate of Limited Partnership[12]
3.2(a)	Second Amended and Restated Agreement of Limited Partnership[2]
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership[3]
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership[4]
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership[5]
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership[6]
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership[8]
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership[9]
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership[14]
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership[15]
3.2(j)	Amendment No. 9 to Second Amended and Restated Agreement of Limited Partnership[12]
3.2(k)	Amendment No. 10 to Second Amended and Restated Agreement of Limited Partnership[30]
4.1	Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership) [2]

4.2(a)	6 5/8% Senior Notes Indenture dated September 28, 2012[26]
4.2(b)	Supplemental Indenture dated as of December 20, 2012[32]
4.3(a)	5 7/8% Senior Notes Indenture dated as of February 11, 2013[10]
4.3(b)	Supplemental Indenture dated as of February 11, 2013[10]
4.4	4 3/4% Senior Notes Indenture dated May 10, 2013[7]
4.5	Certificate of Designation of Class D Convertible Preferred Units[30]
4.6	Registration Rights Agreement, dated May 16, 2012, between Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein[25]
10.1(a)	Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. [1]
10.1(b)	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[14]

Table of Contents

Exhibit No.	Description
10.1(c)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[12]
10.2	Second Amended and Restated Limited Liability Company Agreement of Atlas Pipeline Partners GP, LLC.[19]
10.3(a)	Amended and Restated Credit Agreement dated July 27, 2007, amended and restated as of December 22, 2010, by and among Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the several guarantors and lenders hereto[16]
10.3(b)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011[22]
10.3(c)	Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011[23]
10.3(d)	Amendment No. 2 to the Amended and Restated Credit Agreement dated as of May 31, 2012[27]
10.3(e)	Amendment No. 3 to the Amended and Restated Credit Agreement[31]
10.3(f)	Amendment No. 4 to the Amended and Restated Credit Agreement[34]
10.4	Long-Term Incentive Plan[35]
10.5	Amended and Restated 2010 Long-Term Incentive Plan[22]
10.6	Form of Grant of Phantom Units in Exchange for Bonus Units[17]
10.7	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter[18]
10.8	Form of 2004 Long-Term Incentive Plan Phantom Unit Grant Letter[28]
10.9	Form of Grant of Phantom Units to Non-Employee Managers[11]
10.10	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010[13]
10.11	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010[20]
10.12	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[20]
10.13	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[24]
10.14	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[24]
10.15	Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011[21]
10.16	Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012[25]
10.17	Equity Distribution Agreement dated November 5, 2012, by and between Atlas Pipeline Partners, L.P. and Citigroup Global Markets Inc.[29]
10.18	Class D Preferred Unit Purchase Agreement, dated as of April 17, 2013, among Atlas Pipeline Partners, L.P. and the various purchasers party thereto[33]

10.19	Registration Rights Agreement, dated February 11, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein [(10)]
10.20	Purchase Agreement dated January 28, 2013 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries listed therein, and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers[(26)]
10.21	Registration Rights Agreement, dated May 7, 2013 by and among Atlas Pipeline Partners, L.P. and the purchasers named therein[(30)]
10.22	Registration Rights Agreement, dated May 10, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the guarantors named therein, and Citigroup Global Markets Inc. for itself and on behalf of the initial purchasers[(7)]
10.23	Purchase Agreement dated May 7, 2013 among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, and Citigroup Global Markets Inc. as representatives of the several initial purchasers[(7)]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Atlas Pipeline Partners, L.P.
23.1	Consent of Independent Registered Public Accounting Firm
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification

32.1	Section 1350 Certification
32.2	Section 1350 Certification
101.INS	XBRL Instance Document(36)
101.SCH	XBRL Schema Document(36)
101.CAL	XBRL Calculation Linkbase Document(36)
101.LAB	XBRL Label Linkbase Document(36)
101.PRE	XBRL Presentation Linkbase Document(36)
101.DEF	XBRL Definition Linkbase Document(36)

(1) Filed previously as an exhibit to registration statement on Form S-1 (Registration No. 333-85193).
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on May 13, 2013.
(8) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(9) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(10) Previously filed as an exhibit to current report on Form 8-K filed on February 12, 2013.
(11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
(12) Previously filed as an exhibit to current report on Form 8-K on December 13, 2011.
(13) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
(14) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
(15) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
(16) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
(17) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
(18) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
(19) Previously filed as an exhibit to current report on Form 8-K on October 29, 2013.
(20) Previously filed as an exhibit to Atlas Energy, Inc. s current report on Form 8-K filed on November 12, 2010.
(21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2011.
(22) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2011.
(23) Previously filed as an exhibit to current report on Form 8-K filed on July 11, 2011.
(24) Previously filed as an exhibit to Atlas Energy, L.P. s quarterly report on Form 10-Q for the quarter ended March 31, 2011.
(25) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2012.
(26) Previously filed as an exhibit to current report on Form 8-K filed on January 30, 2013.
(27) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
(28) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2012.
(29) Previously filed as an exhibit to current report on Form 8-K filed on November 6, 2012.
(30) Previously filed as an exhibit to current report on Form 8-K filed on May 8, 2013.
(31) Previously filed as an exhibit to current report on Form 8-K filed on December 13, 2012.
(32) Previously filed as an exhibit to current report on Form 8-K filed on December 26, 2012.
(33) Previously filed as an exhibit to current report on Form 8-K filed on April 17, 2013.

(34) Previously filed as an exhibit to current report on Form 8-K filed on April 23, 2013.
(35) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.
(36) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is unaudited or unreviewed.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	ATLAS PIPELINE PARTNERS, L.P. By: Atlas Pipeline Partners GP, LLC, its General Partner
February 20, 2014	By: /s/ EUGENE N. DUBAY Chief Executive Officer and Managing Board Member of the General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 20, 2014.

/s/ EDWARD E. COHEN Edward E. Cohen	Chairman of the Managing Board of the General Partner
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Vice Chairman of the Managing Board of the General Partner
/s/ EUGENE N. DUBAY Eugene N. Dubay	Chief Executive Officer and Managing Board Member of the General Partner
/s/ ROBERT W. KARLOVICH III Robert W. Karlovich III	Chief Financial Officer and Chief Accounting Officer of the General Partner
/s/ TONY C. BANKS Tony C. Banks	Managing Board Member of the General Partner
/s/ CURTIS D. CLIFFORD Curtis D. Clifford	Managing Board Member of the General Partner
/s/ GAYLE P.W. JACKSON Gayle P.W. Jackson	Managing Board Member of the General Partner
/s/ MARTIN RUDOLPH Martin Rudolph	Managing Board Member of the General Partner
/s/ MICHAEL L. STAINES Michael L. Staines	Managing Board Member of the General Partner

200