ATLAS PIPELINE PARTNERS LP
Form 10-K
February 28, 2013
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, 2012

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 $31.18 per common limited partner unit on June 30, 2012, was approximately $1,505.3 million.

The number of common units of the registrant outstanding on February 25,2013 was 64,557,921

DOCUMENTS INCORPORATED BY REFERENCE: None

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO ANNUAL REPORT

ON FORM 10-K

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;*
- *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 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; 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 8.9% of the limited partner interests in us at December 31, 2012, as well as a 2% general partner interest.

The following chart displays the corporate organizational structure as of December 31, 2012:

Table of Contents

Recent Developments

Acquisitions

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 (Trigger Payments). 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 $598.5 million in cash, including preliminary purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas 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 fifteen 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.

Gas Plant Expansion Projects

In June 2012, we completed construction of, and started processing through, a new 60 MMCFD cryogenic plant at the Velma facility, increasing name-plate processing capacity on our Velma system to 160 MMCFD. This expansion supports our long-term fee-based agreement with XTO Energy, Inc. (XTO), a subsidiary of ExxonMobil, to provide natural gas gathering and processing services for up to an incremental 60 MMCFD from the Woodford Shale.

Table of Contents

In September 2012, we completed construction of, and started processing through, a new 200 MMCFD cryogenic processing plant, referred to as the Waynoka II plant, on our WestOK gathering and processing system. This expansion, located at our Waynoka facility, brings the total name-plate processing capacity on the WestOK system to 458 MMCFD.

Financing

In May 2012, we entered into an amendment to our revolving credit facility agreement, which among other changes: (1) increased the revolving credit facility from $450.0 million to $600.0 million; (2) extended the maturity date from December 22, 2015 to May 31, 2017; and (3) reduced the Applicable Margin used to determine interest rates by 0.50%.

In September 2012, we issued $325.0 million of 6.625% senior unsecured notes due on October 1, 2020 (6.625% Senior Notes) in a private placement transaction. The 6.625% Senior Notes were issued at par. We received net proceeds of $318.9 million and utilized the proceeds to reduce the outstanding balance on our revolving credit facility. We have agreed to file a registration statement with respect to these 6.625% Senior Notes.

In November 2012, we entered into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, we may offer and sell from time to time, through Citigroup, common units having an aggregate value of up to $150.0 million. Such sales will be at market prices prevailing at the time of the sale. We intend to use the net proceeds from any such offering for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital.

In December 2012, in connection with the Cardinal Acquisition, we completed the sale of 10,507,033 common units in a public offering at an offering price of $31.00 per unit and received net proceeds of $319.3 million, including $6.7 million contributed by our General Partner to maintain its 2.0% general partner interest in us. We also issued an additional $175.0 million of 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 approximately 6.0%. We received net proceeds of $176.5 million. We have also agreed to file a registration statement with respect to these 6.625% Senior Notes. We used the net proceeds from these offerings to fund a portion of the purchase price for the Cardinal Acquisition. Additionally, in November 2012 we executed a unit purchase agreement for a private placement of $200.0 million of newly created Class D convertible 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 we raised more than $150.0 million in our common unit equity offering. 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 February 11, 2013 we issued $650.0 million of 5.875% unsecured senior notes due 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.8 million and plan to utilize the proceeds to redeem any or all of our outstanding 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and repay a portion of our outstanding indebtedness under our revolving credit facility. We have agreed to file a registration statement with respect to 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, 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

Table of Contents

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. On February 11, 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. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer. We plan to fund the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

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 Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins; and (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 twelve natural gas processing plants with aggregate capacity of approximately 1,090 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 10,100 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; and the Barnett Shale. Our gathering systems are connected to approximately 8,600 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 operations consist of (1) seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and (2) a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which 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 Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest. The contract gas treating operations are located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford.

Table of Contents

In connection with the Cardinal 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. The fixed fee contract gas treating business acquired in the Cardinal Acquisition generates revenue based upon monthly lease fees. We have included these assets in the Pipeline Transportation segment and renamed it Transportation, Treating and Other .

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

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 objectives by executing on the following:

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 expansions of the Velma and Waynoka processing facilities and our current construction of the Driver and Stonewall plants 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.

Expanding operations through organic growth projects and pursuing strategic acquisitions. We continue to explore opportunities to expand our existing infrastructure. We also plan to continue to pursue strategic acquisitions that leverage our existing asset base, employees and customer relationships. The recent Cardinal 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 rate of return goals 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.

Table of Contents

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. 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 partnership 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.

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, such as our WestTX and Velma operations, 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 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.

Table of Contents

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, 2012, ONEOK Hydrocarbon, L.P. (ONEOK) and Tenaska Marketing Ventures, Inc. accounted for approximately 48% and 15% 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.

Our Gathering and Processing Operations

We own and operate approximately 10,100 miles of intrastate natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. We also own and operate twelve 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 Permian, Anadarko and Appalachian Basins. 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. In the aggregate, our gathering, processing and treating systems have approximately 8,600 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 El Paso Natural Gas Company; Enogex LLC; Kinder Morgan Texas Pipeline; Natural Gas Pipeline Company of America; Northern Natural Gas Company; ONEOK Gas Transportation, LLC; Panhandle Eastern Pipe Line Company, LP; and Southern Star Central Gas Pipeline, Inc. Our processing facilities are connected to NGL pipelines operated by Chaparral Pipeline Company, L.P.; Lone Star NGL LLC; ONEOK and WTLPG.

Table of Contents

Gathering Systems

WestOK. The WestOK gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. The gathering system has approximately 5,400 miles of active natural gas gathering pipelines with approximately 4,500 receipt points. The primary producers on the WestOK gathering system include Chesapeake Energy Corporation and SandRidge Exploration and Production, LLC (Sandridge).

12

Table of Contents

WestTX. The WestTX gathering system, which we operate and in which we have an approximate 72.8% ownership, has approximately 3,300 miles of active natural gas gathering pipelines and approximately 3,100 receipt points 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; Endeavor Energy Resources, LP; and Pioneer.

Table of Contents

Velma. 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 with approximately 600 receipt points consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. The primary producers on the Velma gathering system include BNK Petroleum, Inc.; Merit Management Partners; and XTO.

Table of Contents

Arkoma. The Arkoma gathering systems were acquired as part of the Cardinal Acquisition (see Recent Developments) and are located in the Woodford Shale in southern Oklahoma. The gathering systems have approximately 60 miles of active pipeline with approximately 130 receipt points consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. The primary producers on the Arkoma gathering system include Atoka Midstream LLC and Vanguard Natural Resources LLC.

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 with approximately 20 receipt points consisting primarily of central delivery points, which are linked to multiple wells. The Barnett gas gathering system is used to facilitate gathering the newly-acquired natural gas production of our affiliate, ARP (see Recent Developments).

Tennessee. The Tennessee gathering systems are located in the Appalachian Basin. The gathering systems have approximately 70 miles of natural gas gathering pipelines, with approximately 200 receipt points. 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

WestOK. The WestOK system processes natural gas through three separate plants at the Waynoka 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 December 2006. The Chester processing facility, a 28 MMCFD plant located in Woodward County, Oklahoma, began operations in 1981. A new 30 MMCFD refrigeration plant was placed in operation at the Chaney Dell site in January 2012. We added a new 200 MMCFD cryogenic plant (Waynoka II) at the site of the Waynoka I plant in September 2012 to handle the increases in production from horizontal drilling in the Mississippian Limestone and Carbonate formations in northwest Oklahoma and southern Kansas. 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. The expansion increased the processing capacity at the Waynoka site to 400 MMCFD. We transport and 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 three separate plants at the Consolidator, Midkiff and Benedum processing facilities. The Consolidator plant is a 150 MMCFD cryogenic plant in Reagan County, Texas, which started operations in November 2009. The Benedum plant is a 45 MMCFD cryogenic plant in Upton County, Texas. In October 2011, we refurbished and returned to service the 60 MMCFD cryogenic processing skid from the retired Midkiff plant the Midkiff plant is located at the same site as our Consolidator plant. Our WestTX processing operations have an aggregate processing name-plate capacity of approximately 255 MMCFD. To facilitate increased Spraberry production, we are constructing a new 200 MMCFD cryogenic processing plant, to be known as the Driver plant, which is expected to be in service in the first half of 2013. The additional plant will increase the WestTX aggregate processing name-plate capacity to approximately 455 MMCFD. We transport and sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the WestTX facilities and sell NGL production to ONEOK and DCP NGL Services, LLC (DCP).

Velma. 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 newly-constructed 60 MMCFD cryogenic plant (the V-60 Plant). The Velma plant is one of only two facilities in the area capable of treating both high-content hydrogen sulfide and carbon dioxide gases, which are characteristic in this area. To keep pace with growth of throughput on the Velma system, we constructed the V-60 Plant, which was placed in service in July 2012, expanding the total capacity of the Velma facility to 160 MMCFD. The new V-60 plant supports the additional 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. We transport and sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the Velma facility and sell NGL production to ONEOK.

Arkoma. The Arkoma system processes and treats natural gas through three separate processing plants at the Atoka, Coalgate and Tupelo processing facilities and the East Rockpile treating facility, all of which were acquired in the Cardinal Acquisition (see Recent Developments). These facilities also process natural gas gathered by 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, to be known as the Stonewall plant, which will be 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 Arkoma aggregate processing name-plate capacity to approximately 340 MMCFD. We transport and sell natural gas to various parties, including marketing companies and pipelines, at the tailgate of the Arkoma facilities and sell NGL production to ONEOK.

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 recently entered into a new 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. 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 area.

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, swing gas, which is natural gas sold during the current month, is sold daily at various *Platt s Gas Daily* midpoint prices. The Arkoma system has access to Centerpoint Energy, Inc.; Enogex LLC; and MarkWest Energy Partner s Arkoma Connector Pipeline. The Velma system has access to ONEOK Gas Transportation, LLC; Southern Star Central Gas Pipeline, Inc.; and Natural Gas Pipeline Company of America. 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 Kinder Morgan Texas Pipeline; Northern Natural Gas Company; and El Paso Natural Gas Company.

We sell most of our NGL production to ONEOK under four separate agreements. The WestTX agreement has a term expiring in 2013; the WestOK agreement has a term expiring in 2014; the Velma agreement has a term expiring at the end of 2016; and the Arkoma agreement has a term expiring in 2024. We have signed agreements with DCP NGL Services, LLC (DCP), a subsidiary of DCP Midstream, LLC, to sell our NGL production from our WestOK, WestTX and Velma processing facilities upon the expiration of each of the ONEOK agreements. The DCP agreements each have a term of fifteen years. DCP has agreed to purchase NGL production from our WestTX processing facilities, on an interim basis, under the same terms as the new agreement with DCP, for those volumes which are in excess of the volumes sold under the ONEOK agreement. At WestOK, we sell NGL production at the Chaney Dell plant to Murphy Energy Corporation. 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/or fractionation fees and/or quality adjustment fees.

Table of Contents

Condensate is collected at the Arkoma plants and gathering systems and currently sold to Enterprise Products Partners, L.P. Condensate is collected at the Velma gas plants and gathering systems and currently sold to EnerWest Trading Company, LLC. Condensate collected at the WestOK plants and gathering systems is currently sold to Plains Marketing, L.P. Condensate collected at the WestTX plants and gathering systems is currently sold to Plains Marketing, L.P. and Occidental Energy Marketing, Inc.

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 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 our being long physical NGLs and short physical 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.

Table of Contents

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.

Contract Gas Treating. The gas treating facilities acquired in the Cardinal Acquisition (see Recent Developments) 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 were either outbid by others or 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.

Table of Contents

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; Copano Energy, LLC; Crosstex Energy Services, L.P.; DCP Midstream, LLC; Energy Transfer Partners, L.P.; Enogex, LLC; Lumen Midstream Partners, LLC; MarkWest Energy Partners, L.P.; Mustang Fuel Corporation; ONEOK Field Services Company, LLC; Scissor Tail Energy, LLC; SemGas, L.P.; Southern Union Company; Superior Pipeline Company, LLC; Targa Resources Partners LP; 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 our relationships with operators connected to our system are good and that we present an attractive alternative for producers. However, if we cannot compete successfully, 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 NGL Services, LLC; 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 Kinder Morgan Energy Partners, L.P.; Spartan Energy Partners LLC; Zephyr Gas Services LLC; and TransTex Hunter, LLC.

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;
- location of our transportation systems relative to our competitors; and
- the responsiveness to a customer s needs.

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.

20

Table of Contents

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; and
- 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 and 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.

Table of Contents

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

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

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

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

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

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, certain storage vessels and compressor

Table of Contents

stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require obtaining 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. Recently, the EPA issued amended regulations that will affect operation of a portion of our compressor engine fleet by requiring implementation of new monitoring requirements in calendar year 2013.

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 new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur 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.

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 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. 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. These facilities are the Velma, Chaney Dell, Waynoka, and Chester gas processing plants in Oklahoma and the Midkiff and Benedum gas processing plants in Texas. 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. 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. The natural gas industry is covered by the rule and requires annual greenhouse gas emissions to be reported for 2012 no later than April 1, 2013. 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 discussion 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.

Table of Contents

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.

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 a certification to regulate intrastate gas pipeline facilities. The Oklahoma Corporation Commission and the Texas Railroad Commission also have a 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 its pipeline facilities. However, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, the activities need 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. 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.

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

In the first half of 2013 we expect to complete and place into service a new gas transmission pipeline extending from our Driver processing plant in West Texas over ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. We call this pipeline the Driver Residue Pipeline and will own it with Pioneer. We will operate the Driver Residue Pipeline. 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.

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.

The Oklahoma Corporation Commission and Texas Railroad Commission both have authority to regulate rates for common carrier pipelines in their respective jurisdictions. Historically, this regulation has been light-handed.

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.

Table of Contents

We acquired an approximately fifteen mile NGL pipeline located in Oklahoma in connection with our Cardinal Acquisition (see Recent Developments). We believe 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 Natural Gas Act has been amended 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. 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. Accordingly, the provisions of the Energy Policy Act have only limited applicability to us, primarily in our capacity as a seller of natural gas, and as the operator of interstate natural gas pipelines subject to limited jurisdiction certificates.

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

Table of Contents

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.

Properties

Our principal facilities consist of twelve natural gas processing plants; eighteen gas treating facilities; approximately 10,100 miles of active 2 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.

Table of Contents

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

Gas Processing Facilities

Facility	Location	Year Constructed	Design Throughput Capacity (MMCFD)	2012 Average Througput (MMCFD)	2012 Average Utilization Rate
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	348	76%
Consolidator plant	Reagan County, TX	2009	150		
Midkiff plant	Reagan County, TX	1990	60		
Benedum plant	Upton County, TX	Updated 1981	45		
Total WestTX			255	249	98%
Velma plant	Stephens County, OK	Updated 2003	100		
Velma V-60 plant	Stephens County, OK	2012	60		
Total Velma			160	114	71%
East Rockpile Treating	Pittsburg County, OK	2008			
Atoka plant	Atoka County, OK	2006	20		
Coalgate plant	Coal County, OK	2007	80		
Tupelo plant	Coal County, OK	2011	120		
Total Arkoma			220	211	96%
Total			1,093	922	84%

Natural Gas Gathering Systems

System	Location	Approximate Active Miles of Pipe	Approximate Number of Receipt Points
WestOK	North Central Oklahoma and Southern Kansas	5,400	4,500
Velma	Southern Oklahoma and Northern Texas	1,200	600
WestTX	West Texas	3,300	3,100
Arkoma	Southern Oklahoma	60	130
Tennessee	Tennessee	70	200
Barnett Shale	Central Texas	20	20
Total		**10,050**	**8,550**

Natural Gas Treating Facilities

Location	Type	Number of Units
Oklahoma	Refrigeration	1
Texas	Refrigeration	1
Total Refrigeration		2
Arkansas	Amine	1
Texas	Amine	9
Louisiana	Amine	2
In inventory	Amine	3
Total Amine		15

Table of Contents

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 350 people at December 31, 2012 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. If these separate activities are significantly greater than our activities, 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, 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.

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 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.

The continuing 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 2013 market prices for NGLs, natural gas and crude oil, based upon NYMEX forward price curves as of January 2, 2013, were $0.91 per gallon, $3.45 per MMBTU and $94.16 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended December 31, 2013 by approximately $13.5 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 $77.69 per barrel to $109.77 per barrel in 2012, while Henry Hub natural gas prices have traded in a range of $1.91 per MMBTU to $3.90 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;

- 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 promulgated by the Commodities 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 to be adopted by the Commodities 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. 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 wells 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 2012, Chesapeake Energy Corporation; COG Operating LLC; Endeavor Energy Resources LP; Energen Resources Corporation; Laredo Petroleum Inc.; Parsley Energy, LP; Pioneer; Range Resources Corporation; SandRidge Exploration and Production, 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; Copano Energy, LLC; DCP Midstream, LLC; Energy Transfer Partners, LP; Enogex, LLC and ONEOK Field Services Company, operate competing gathering systems and processing plants in our Velma service area.

- Access Midstream Partners, LP; DCP Midstream, LLC; Caballo Energy, LLC.; 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; Southern Union Company; Targa Resources Partners; and West Texas Gas, Inc. operate competing gathering systems and processing plants in our WestTX service area.

- Enogex, LLC; MarkWest Energy Partners, L.P.; and Scissor Tail Energy LLC operate competing gathering systems and processing plants in our Anadarko 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. If we do not compete successfully, the amount of natural gas we gather and process will decrease, reducing our gross margin and cash flow.

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, 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.

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

Any acquisition, including our recent Cardinal Acquisition (see Recent Developments), 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;

Table of Contents

- delays in obtaining any required regulatory approvals or third party consents;
- the imposition of conditions on any acquisition by a regulatory authority;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel;
- customer or key employee losses at the acquired businesses; and
- the failure to realize expected growth or profitability.

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

We may be unsuccessful in integrating the operations from the Cardinal Acquisition, 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 the operations acquired through the Cardinal Acquisition (see Recent Developments), or other 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.

Table of Contents

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. 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 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;

Table of Contents

- 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.

Increases in interest rates could adversely affect our unit price.

Credit markets recently have experienced record lows in 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.

Table of Contents

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, 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 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. 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. 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 industry. The outcomes of such activities can impact our operations. For example, the Center for Biological Diversity (CBD) recently notified the U.S. Army Corp of Engineers (the Corp) of its intent to file a lawsuit to challenge the Corp s administration of the Nationwide Permit (NWP) program, a program used by the oil and gas industry to permit pipeline construction projects. Unless the Corp acts to correct alleged Endangered Species Act violations, the CBD has threatened further litigation to immediately suspend the NWP program.

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; 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, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring 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

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.

Terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Our insurance policies generally exclude acts of terrorism. Such insurance is not available at what we believe to be acceptable pricing levels.

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 an 8.9% 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.

Table of Contents

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.

Our control of the WestOK and WestTX systems is limited by provisions of the limited liability company operating agreements with Anadarko and, with respect to the WestTX system, the operation and expansion agreement with Pioneer. Our control of Centrahoma is limited by provisions of the joint venture agreement with MarkWest.

The managing member of each of the limited liability companies, which owns the interests in the WestOK and WestTX systems, is our subsidiary. However, the consent of Anadarko is required 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. The WestTX system is also governed by an operation and expansion agreement with Pioneer, which gives system owners having at least a 60% interest in the system the right to approve the annual operating budget and capital investment budget and to impose other limitations on the operation of the system. Thus, a holder of a greater than 40% interest in the system would effectively have a veto right over the operation of the system. Pioneer currently owns an approximate 27% interest in the system.

Similarly, we own a 60% interest in Centrahoma. The consent of MarkWest, which owns a 40% interest, will be required for specified transactions, such as approving expenses in excess of $100,000; approving any expansion proposals; modifying, amending or terminating certain gas processing and facilities operating agreements; entering into any new gas processing agreements that materially differ from its existing gas processing agreements; approving contracts between Centrahoma and us or any of our subsidiaries; amending the limited liability company operating agreement; and authorizing any acts that are not in the ordinary course of business of Centrahoma. Thus, while we own a majority interest in Centrahoma, MarkWest will effectively have a veto right over most operations of Centrahoma.

We own a non-controlling interest in WTLPG and may have limited ability to influence significant business decisions affecting this entity.

We have a 20% non-controlling ownership interest in WTLPG, which means we have limited ability to influence the business decisions of this entity. In addition, we may be unable to control the amount of cash we will receive from the operation of WTLPG and we 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

Table of Contents

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.

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.

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, Texas and Kansas. Each of those states, except Texas, 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

Table of Contents

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

N/A

ITEM 2: PROPERTIES

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

ITEM 3: LEGAL PROCEEDINGS

N/A

ITEM 4: MINE SAFETY DISCLOSURES

N/A

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 25, 2013, the closing price for the common units was $33.02 there were 96 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, 2012 and 2011:

	High	Low	Distributions Declared
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
2011			
Fourth Quarter	$ 37.20	$ 26.50	$ 0.55
Third Quarter	35.44	24.12	0.54
Second Quarter	37.90	30.10	0.47
First Quarter	34.74	23.42	0.40

Our Cash Distribution Policy

Our partnership agreement requires we distribute 100% of available cash to our General Partner and common limited partners within 45 days following the end of each 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.

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 unitholders exceed specified targets, as follows:

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, 2012 and 2011 were $6.3 million and $1.7 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, 2012, 2011 and 2010 and at December 31, 2012 and 2011 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, 2009 and 2008 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, 2012	2011	2010	2009	2008
			(in thousands)		
Statements of operations data:					
Revenue:					
Natural gas and liquids sales	$ 1,137,261	$ 1,268,195	$ 890,048	$ 636,231	$ 1,078,714
Transportation, processing and other fees	66,722	43,799	41,093	59,075	87,442
Derivative gain (loss)	31,940	(20,452)	(5,945)	(35,815)	29,741
Other income, net	10,097	11,192	10,392	13,114	6,844
Total revenues	1,246,020	1,302,734	935,588	672,605	1,202,741
Costs and expenses:					
Natural gas and liquids cost of sales	927,946	1,047,025	720,215	527,730	900,460
Plant operating	60,480	54,686	48,670	45,566	47,371
Transportation and compression	1,618	833	1,061	6,657	11,249
General and administrative[(1)]	47,206	36,357	34,021	37,280	(2,933)
Other costs	15,069	1,040			
Depreciation and amortization	90,029	77,435	74,897	75,684	71,764
Goodwill and other asset impairment loss				10,325	615,724
Interest	41,760	31,603	87,273	101,309	87,422
Total costs and expenses	1,184,108	1,248,979	966,137	804,551	1,731,057
Equity income in joint venture	6,323	5,025	4,920	4,043	
Gain (loss) on asset sales and other[(2)]		256,272	(10,729)	108,947	
Gain (loss) on early extinguishment of debt		(19,574)	(4,359)	(2,478)	17,420
Income (loss) from continuing operations before tax	68,235	295,478	(40,717)	(21,434)	(510,896)
Income tax expense	176				
Income (loss) from continuing operations	68,059	295,478	(40,717)	(21,434)	(510,896)
Income (loss) from discontinued operations net of tax		(81)	321,155	84,148	(93,802)
Net income (loss)	68,059	295,397	280,438	62,714	(604,698)
(Income) loss attributable to non-controlling interests[(3)]	(6,010)	(6,200)	(4,738)	(3,176)	22,781
Preferred unit imputed dividend cost					(505)
Preferred unit dividends		(389)	(780)	(900)	(1,769)
Net income (loss) attributable to common limited partners and the General Partner	$ 62,049	$ 288,808	$ 274,920	$ 58,638	$ (584,191)

Table of Contents

	2012	2011	2010	2009	2008
	Years Ended December 31, (in thousands, except per unit data)				
Allocation of net income (loss) attributable to:					
Common limited partner interest:					
Continuing operations	$ 52,391	$ 281,449	$ (45,347)	$ (24,997)	$ (503,533)
Discontinued operations		(79)	315,021	82,457	(91,917)
	52,391	281,370	269,674	57,460	(595,450)
General Partner interest:					
Continuing operations	9,658	7,440	(888)	(513)	13,144
Discontinued operations		(2)	6,134	1,691	(1,885)
	9,658	7,438	5,246	1,178	11,259
Net income (loss) attributable to:					
Continuing operations	62,049	288,889	(46,235)	(25,510)	(490,389)
Discontinued operations		(81)	321,155	84,148	(93,802)
	$ 62,049	$ 288,808	$ 274,920	$ 58,638	$ (584,191)
Net income (loss) attributable to common limited partners per unit:					
Basic:					
Continuing operations	$ 0.95	$ 5.22	$ (0.85)	$ (0.52)	$ (11.80)
Discontinued operations			5.92	1.71	(2.16)
	$ 0.95	$ 5.22	$ 5.07	$ 1.19	$ (13.96)
Diluted(4):					
Continuing operations	$ 0.95	$ 5.22	$ (0.85)	$ (0.52)	$ (11.80)
Discontinued operations			5.92	1.71	(2.16)
	$ 0.95	$ 5.22	$ 5.07	$ 1.19	$ (13.96)
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 2,200,381	$ 1,567,828	$ 1,341,002	$ 1,327,704	$ 1,415,517
Total assets	3,065,638	1,930,812	1,764,848	2,137,963	2,413,196
Total debt, including current portion	1,179,918	524,140	565,974	1,254,183	1,493,427
Total equity	1,606,408	1,236,228	1,041,647	723,527	650,842
Cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 174,638	$ 102,867	$ 106,427	$ 55,853	$ (59,194)
Investing activities	(1,006,641)	67,763	594,753	241,123	(292,944)
Financing activities	835,233	(170,626)	(702,037)	(297,400)	341,242
Other financial data (unaudited):					
Gross margin from continuing operations (5)	$ 278,128	$ 264,923	$ 210,580	$ 163,677	$ 273,493
EBITDA (6)	194,014	398,235	450,543	256,368	(409,397)
Adjusted EBITDA (6)	220,207	181,026	209,799	174,808	322,515
Maintenance capital expenditures	$ 19,021	$ 18,247	$ 10,921	$ 3,750	$ 4,787
Expansion capital expenditures	354,512	227,179	35,715	106,524	176,869
Total capital expenditures	$ 373,533	$ 245,426	$ 46,636	$ 110,274	$ 181,656

Table of Contents

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Operating data (unaudited):					
Velma system:					
Gathered gas volume (MCFD)	128,548	103,328	84,455	76,378	63,196
Processed gas volume (MCFD)	114,421	98,126	78,606	73,940	60,147
Residue Gas volume (MCFD)	100,711	80,330	64,138	58,350	47,497
NGL volume (BPD)	13,850	11,433	9,218	8,232	6,689
Condensate volume (BPD)	409	423	416	377	280
WestOK system:					
Gathered gas volume (MCFD)	369,035	268,329	228,684	270,703	276,715
Processed gas volume (MCFD)	348,041	254,394	214,695	215,374	245,592
Residue Gas volume (MCFD)	322,751	230,907	193,200	228,261	239,498
NGL volume (BPD)	14,505	13,635	12,395	13,418	13,263
Condensate volume (BPD)	1,360	898	697	824	791
WestTX system(7):					
Gathered gas volume (MCFD)	275,946	212,775	178,111	159,568	144,081
Processed gas volume (MCFD)	249,221	196,412	163,475	149,656	135,496
Residue Gas volume (MCFD)	179,539	133,857	105,982	101,788	92,019
NGL volume (BPD)	32,314	29,052	26,678	21,261	19,538
Condensate volume (BPD)	1,524	1,500	1,289	1,265	1,142
Arkoma system(7):					
Gathered gas volume (MCFD)	222,045				
Processed gas volume (MCFD)	211,032				
NGL volume (BPD)	16,138				
Condensate volume (BPD)	122				
Barnett system:					
Average throughput volume (MCFD)	22,935				
Tennessee system:					
Average throughput volume (MCFD)	8,487	7,698	8,740	7,907	1,951
WTLPG system(7):					
Average throughput volume (BPD)	249,533	229,673			

(1) Includes non-cash compensation (income) expense of $11.6 million, $3.3 million, $3.5 million, $0.7 million and ($34.0) million for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively; and includes compensation reimbursement to affiliates.

(2) Represents the gain on sale of assets to Laurel Mountain Midstream, LLC (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 s non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest s non-controlling interest in Centrahoma.

(4) For the years ended December 31, 2010, 2009 and 2008, approximately 300,000, 82,000 and 146,000 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 years ended December 31, 2010 and 2009, 75,000 and 100,000 unit options were excluded, respectively, 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. For the year ended December 31, 2008 potential common limited partner units issuable upon conversion of our $1,000 par value Class A and Class B cumulative convertible preferred limited partner 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.

(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):

Table of Contents

RECONCILIATION OF GROSS MARGIN FROM CONTINUING OPERATIONS

	Years Ended December 31,				
	2012	2011	2010	2009	2008
			(in thousands)		
Net income (loss)	$ 68,059	$ 295,397	$ 280,438	$ 62,714	$ (604,698)
Derivative (gain) loss, net	(31,940)	20,452	5,340	35,372	(29,741)
Other income, net	(10,097)	(11,192)	(9,787)	(12,671)	(6,844)
Operating expenses[8]	77,167	56,559	49,731	52,223	58,620
General and administrative expense[1]	47,206	36,357	34,021	37,280	(2,933)
Depreciation and amortization	90,029	77,435	74,897	75,684	71,764
Interest	41,760	31,603	87,273	101,309	87,422
Income tax expense	176				
Equity income in joint venture	(6,323)	(5,025)	(4,920)	(4,043)	
Gain on asset sale[2]		(256,272)	10,729	(108,947)	
(Gain) loss on early extinguishment of debt		19,574	4,359	2,478	(17,420)
Goodwill and other asset impairment				10,325	615,724
Non-cash linefill (gain) loss [9]	2,111	(46)	(346)	(3,899)	7,797
(Income) loss from discontinued operations		81	(321,155)	(84,148)	93,802
Gross margin from continuing operations	$ 278,148	$ 264,923	$ 210,580	$ 163,677	$ 273,493

(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 below is similar to the Consolidated EBITDA calculation utilized within our financial covenants under our credit facility, with the exception that Adjusted EBITDA includes EBITDA from the discontinued operations related to the sale of Elk City and other 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.

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,				
	2012	2011	2010	2009	2008
			(in thousands)		
Net income (loss)	$ 68,059	$ 295,397	$ 280,438	$ 62,714	$ (604,698)
Adjustments:					
(Income) loss attributable to non-controlling interests from continuing operations[3]	(6,010)	(6,200)	(4,738)	(3,176)	22,781
Interest expense	41,760	31,603	87,273	101,309	87,422
Other interest			604	443	
Income tax expense	176				
Depreciation and amortization	90,029	77,435	74,897	75,684	71,764
Discontinued operations interest expense, depreciation and amortization			12,069	19,394	13,334
EBITDA	194,014	398,235	450,543	256,368	(409,397)
Adjustments:					
Equity income in joint venture	(6,323)	(5,025)	(4,920)	(4,043)	
Distributions from joint venture	7,200	4,448	11,066	4,310	
Long-lived asset impairment loss				10,325	
Goodwill impairment loss, net of associated non-controlling interest					585,053
Gain on asset sales and other[10]		(256,191)	(301,373)	(162,518)	
Loss on early extinguishment of debt		19,574	4,359	2,478	2,447
Non-cash (gain) loss on derivatives	(23,283)	4,538	(10,166)	74,644	(113,640)
Acquisition cost	15,395				
Unrecognized economic impact of Cardinal Acquisition[11]	1,698				
Net cash derivative early termination expense[12]			22,401	2,260	102,146
Premium expense on derivative instruments	17,759	12,219	21,123	9,693	3,736
Non-cash compensation (income) expense	11,636	3,274	3,484	701	(34,010)
Non-cash linefill (gain) loss [9]	2,111	(46)	(346)	(3,899)	7,797
Discontinued operations adjustments[13]			13,628	(15,511)	178,383
Adjusted EBITDA	$ 220,207	$ 181,026	$ 209,799	$ 174,808	$ 322,515

(7) Operating data for Arkoma, WestTX and WTLPG represent 100% of the operating activity for the respective systems.
(8) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.
(9) Represents the non-cash impact of commodity price movements on pipeline linefill.
(10) 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 (see Item 8. Financial Statements and Supplementary Data Note 5) 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.
(11) Represents the earnings from the Cardinal Acquisition (see Item 1. Business Recent Developments) 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 the Cardinal Acquisition.
(12) During the years ended December 31, 2010, 2009 and 2008, we made net payments of $33.7 million, $5.0 million and $274.0 million, respectively, which resulted in a net cash expense recognized of $33.7 million, $5.0 million and $197.6 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. In 2008, we entered into an amendment to our credit facility to revise the definition of Consolidated EBITDA to allow for the add-back of charges relating to the early termination of certain derivative contracts for debt covenant calculation purposes when the early termination of derivative contracts is funded through the issuance of common equity.
(13)

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

Table of Contents

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 Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in 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 twelve natural gas processing plants with aggregate capacity of approximately 1,090 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 10,100 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; and the Barnett Shale. Our gathering systems are connected to approximately 8,600 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 operations consist of (1) seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and (2) a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation.

Table of Contents

WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest. The contract gas treating operations are located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford.

In connection with the Cardinal 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. The fixed fee contract gas treating business acquired in the Cardinal Acquisition generates revenue based upon monthly lease fees. We have included these assets in the Pipeline Transportation segment and renamed it Transportation, Treating and Other .

Recent Events

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 (Trigger Payments). In connection with this acquisition, we received assignment of gas purchase agreements for gas then currently gathered on the acquired system.

On May 31, 2012, we entered into an amendment to the revolving credit facility agreement, which among other changes: (1) increased the revolving credit facility from $450.0 million to $600.0 million; (2) extended the maturity date from December 22, 2015 to May 31, 2017; (3) reduced the Applicable Margin used to determine interest rates by 0.50%; (4) revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the Credit Agreement) or $340.0 million, provided we meet certain requirements, and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets; (5) revised the definition of Consolidated EBITDA to provide for the inclusion of the first twelve months of projected revenues for identified capital expansion projects, upon completion of the projects up to a maximum of 15% of Consolidated Net Tangible Assets; and (6) provided for the option of requesting additional revolving credit commitments of up to $200.0 million (see Revolving Credit Facility).

In June 2012, we completed construction of, and started processing through, a 60 MMCFD cryogenic facility at the Velma gas processing facility, increasing capacity at Velma to 160 MMCFD. This expansion supports our long-term fee-based agreement with XTO Energy, Inc., a subsidiary of ExxonMobil, to provide natural gas gathering and processing services for up to an incremental 60 MMCFD from the Woodford Shale.

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. (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 September 2012, we issued $325.0 million of 6.625% senior unsecured notes due on October 1, 2020 (6.625% Senior Notes) in a private placement transaction. The 6.625% Senior Notes were issued at par. We received net proceeds of $318.9 million and utilized the proceeds to reduce the outstanding balance on our revolving credit facility (see Senior Notes). We have agreed to file a registration statement with respect to these 6.625% Senior Notes.

Table of Contents

In September 2012, we completed construction of, and started processing through, a 200 MMCFD cryogenic processing plant, referred to as the Waynoka II plant, on our WestOK gathering and processing system. This expansion brings the total name-plate processing capacity on the WestOK system to 458 MMCFD.

In November 2012, we entered into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, we may offer and sell from time to time, through Citigroup, common units having an aggregate value of up to $150.0 million. Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. We intend to use the net proceeds from any such offering for general partnership purposes (see Common Equity Offerings).

In December 2012, we acquired 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $598.5 million in cash, including preliminary purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies represent the majority of the operating assets of Cardinal and include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas 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 fifteen 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 December 2012, in connection with the Cardinal Acquisition, we completed the sale of 10,507,033 common units in a public offering at an offering price of $31.00 per unit and received net proceeds of $319.3 million, including $6.7 million contributed by our General Partner for the General Partner to maintain its 2.0% general partner interest in us. We also issued an additional $175.0 million of 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 $176.5 million (see Senior Notes). We have also agreed to file a registration statement with respect to these 6.625% Senior Notes. We used the net proceeds from these offerings to fund a portion of the Cardinal Acquisition (see Common Equity Offerings). Additionally, in November 2012 we executed a unit purchase agreement for a private placement of $200 million of newly created Class D convertible 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 we raised more than $150.0 million in our common unit equity offering. 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.

In December 2012, we entered into an amendment to our credit agreement which provided for (1) the Cardinal Acquisition to be a permitted investment; and (2) Centrahoma to not be required to be a guarantor nor provide a security interest in its assets (see Revolving Credit Facility).

Subsequent Events

On January 7, 2013, we paid $6.0 million for the first of two Trigger 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 Trigger Payment (see Recent Events).

On February 11, 2013 we issued $650.0 million of 5.875% unsecured senior notes due 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.8 million and plan to utilize the proceeds to redeem any or all of our outstanding 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and repay a portion of our outstanding indebtedness under our revolving credit facility. We have agreed to file a registration statement with respect to 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, 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. On February 11, 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. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer. We plan to fund the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

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 December 2012, we completed the Cardinal Acquisition for $598.5 million in cash, including preliminary purchase price adjustments, less cash received (see Recent Events).

Dispositions

In September 2010, we completed the sale of our Elk City and Sweetwater, Oklahoma natural gas gathering systems, and the related processing and treating facilities (including the Prentiss treating facility and the Nine Mile processing plant, collectively Elk City) to a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) for $682.0 million in cash, excluding working capital adjustments and transaction costs, and recognized a gain of $312.1 million within discontinued operations.

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 and the sale of natural gas, NGLs and condensate. 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.

Revenue consists of the sale of natural gas, NGLs and condensate; and the fees earned from our gathering, processing and treating operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas, NGLs and condensate off delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. (See Item 8. Financial Statements and Supplementary Data Note 2 Revenue Recognition for further discussion of contractual revenue arrangements).

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 plus transportation, processing and other fees 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.

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, 2012, 2011 and 2010 (in thousands):

RECONCILIATION OF DISTRIBUTABLE CASH FLOW

	Years Ended December 31,		
	2012	**2011**	**2010**
		(In thousands)	
Adjusted EBITDA[(1)]	$ 220,207	$ 181,026	$ 209,799
Interest expense[(2)]	(41,760)	(31,603)	(87,835)
Amortization of deferred finance costs	4,672	4,480	6,186
Preferred dividend obligation		(389)	(780)
Proceeds remaining from asset sale[(3)]		5,850	
Premium expense on derivative instruments[(2)]	(17,759)	(12,219)	(28,320)
Other costs	(326)	1,040	
Maintenance capital	(19,021)	(18,247)	(12,179)
Distributable Cash Flow	$ 146,013	$ 129,938	$ 86,871

(1) See Item 6. Selected Financials Reconciliation of net income to EBITDA and Adjusted EBITDA
(2) For the year ended December 31, 2010, includes amounts recorded within discontinued operations.
(3) 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 due 2018.

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,				
	2012	2011	Percent Change	2010	Percent Change
Pricing:					
Weighted Average Prices:					
NGL price per gallon Conway hub	$ 0.78	$ 1.08	(27.8)%	$ 0.92	17.4%
NGL price per gallon Mt. Belvieu hub	0.96	1.31	(26.7)%	1.03	27.2%
Natural gas sales ($/Mcf):					
Velma	2.60	3.86	(32.6)%	4.14	(6.8)%
WestOK	2.66	3.87	(31.3)%	4.13	(6.3)%
WestTX	2.54	3.84	(33.9)%	4.10	(6.3)%
Weighted Average	2.62	3.86	(32.1)%	4.12	(6.3)%
NGL sales ($/gallon):					
Velma	0.78	1.11	(29.7)%	0.90	23.3%
WestOK	0.89	1.10	(19.1)%	0.94	17.0%
WestTX	0.98	1.33	(26.3)%	1.02	30.4%
Weighted Average	0.90	1.20	(25.0)%	0.97	23.7%
Condensate sales ($/barrel):					
Velma	94.82	94.35	0.5%	78.28	20.5%
WestOK	84.76	86.63	(2.2)%	72.67	19.2%
WestTX	89.40	92.84	(3.7)%	75.57	22.9%
Weighted Average	87.88	90.65	(3.1)%	75.08	20.7%
Operating data:					
Velma system:					
Gathered gas volume (MCFD)	128,548	103,328	24.4%	84,455	22.3%
Processed gas volume (MCFD)	114,421	98,126	16.6%	78,606	24.8%
Residue gas volume (MCFD)	100,711	80,330	25.4%	64,138	25.2%
NGL volume (BPD)	13,850	11,433	21.1%	9,218	24.0%
Condensate volume (BPD)	409	423	(3.3)%	416	1.7%
WestOK system:					
Gathered gas volume (MCFD)	369,035	268,329	37.5%	228,684	17.3%
Processed gas volume (MCFD)	348,041	254,394	36.8%	214,695	18.5%
Residue gas volume (MCFD)	322,751	230,907	39.8%	193,200	19.5%
NGL volume (BPD)	14,505	13,635	6.4%	12,395	10.0%
Condensate volume (BPD)	1,360	898	51.4%	697	28.8%
WestTX system[1]:					
Gathered gas volume (MCFD)	275,946	212,775	29.7%	178,111	19.5%
Processed gas volume (MCFD)	249,221	196,412	26.9%	163,475	20.1%
Residue gas volume (MCFD)	179,539	133,857	34.1%	105,982	26.3%
NGL volume (BPD)	32,314	29,052	11.2%	26,678	8.9%
Condensate volume (BPD)	1,524	1,500	1.6%	1,289	16.4%
Arkoma system[1]:					
Gathered gas volume (MCFD)	222,045				
Processed gas volume (MCFD)	211,032				
NGL volume (BPD)	16,138				
Condensate volume (BPD)	122				
Barnett system:					
Average throughput volumes (MCFD)	22,935				
Tennessee system:					
Average throughput volumes (MCFD)	8,487	7,698	10.2%	8,740	(11.9)%
WTLPG system[1]:					
Average throughput volumes (BPD)	249,533	229,673	8.6%		100.0%

(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, 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%
Total revenues for gross margin	1,203,983	1,311,994	(108,011)	(8.2)%
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%
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]	$ 194,014	$ 398,235	$ (204,221)	(51.3)%
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 Velma 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 (see Recent Events).

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 (see Recent Events).

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 Recent Events).

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 unsecured notes due on December 15, 2015 (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 (see Recent Events). 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

Table of Contents

Cardinal Acquisition (see Recent Events). 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).

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 year 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.

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

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2011 and 2010 (in thousands):

	Years Ended December 31, 2011	2010	Variance	Percent Change
Gross margin[(1)]				
Natural gas and liquids sales	$ 1,268,195	$ 890,048	$ 378,147	42.5%
Transportation, processing and other fees	43,799	41,093	2,706	6.6%
Total revenues for gross margin	1,311,994	931,141	380,853	40.9%
Less: natural gas and liquids cost of sales	1,047,025	720,215	(326,810)	(45.4)%
Less: non-cash linefill gain[(2)]	46	346	300	86.7%
Gross margin	264,923	210,580	54,343	25.8%
Expenses:				
Operating expenses	56,559	49,731	6,828	13.7%
General and administrative[(3)]	36,357	34,021	2,336	6.9%
Depreciation and amortization	77,435	74,897	2,538	3.4%
Interest expense	31,603	87,877	(56,274)	(64.0)%
Total expenses	201,954	246,526	(44,572)	(18.1)%

71

Table of Contents

	Years Ended December 31, 2011	2010	Variance	Percent Change
Other income items:				
Derivative loss, net	(20,452)	(5,340)	(15,112)	(283.0)%
Other income, net	11,192	10,391	801	7.7%
Non-cash linefill gain (loss)(2)	46	346	(300)	(86.7)%
Equity income in joint ventures	5,025	4,920	105	2.1%
Gain (loss) on asset sales and other(4)	256,272	(10,729)	267,001	2,488.6%
Loss on early extinguishment of debt	(19,574)	(4,359)	(15,215)	(349.0)%
Income (loss) from discontinued operations	(81)	321,155	(321,236)	(100.0)%
Income attributable to non-controlling interests(5)	(6,200)	(4,738)	(1,462)	(30.9)%
Preferred unit dividends	(389)	(780)	391	50.0%
Net income attributable to common limited partners and General Partner	$ 288,808	$ 274,920	$ 13,888	5.1%
Non-GAAP financial data:				
EBITDA(1)	$ 398,235	$ 450,543	$ (52,308)	(11.6)%
Adjusted EBITDA(1)	181,026	209,799	(28,773)	(13.7)%
Distributable cash flow(1)	129,938	86,871	43,067	49.6%

(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 of Laurel Mountain.
(5) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX

Gross margin:

Gross margin for the year ended December 31, 2011 increased as a result of higher realized commodity prices combined with higher production volumes across all systems.

Volumes on the Velma system increased for the year ended December 31, 2011 when compared to the prior year period primarily due to new production gathered on the Madill-to-Velma gas gathering pipeline.

Volume on the WestOK system increased for the year ended December 31, 2011 compared to the prior year due to the completion of an expansion into Kansas in June 2010.

WestTX system volumes for the year ended December 31, 2011 increased when compared to the prior year period due to increased volumes from Pioneer as a result of their continued drilling program.

Expenses:

Operating expense for the year ended December 31, 2011 increased primarily due to increased gathered and processed volumes in comparison to the prior year period, as operating expenses are generally dependent on activity in our systems.

Interest expense for the year ended December 31, 2011 decreased primarily due to a $21.1 million decrease in interest expense associated with our term loan being retired during the prior year; a $16.4 million decrease in interest expense associated with the 8.125% Senior Notes; and an $11.6 million decrease in interest expense associated with our revolving credit facility. The lower interest expense on our term loan and revolving credit facility is due to the retirement of the term loan and a reduction of the credit facility borrowings with proceeds from the sale of Elk City (see Dispositions). 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).

Other income items:

Derivative gain (loss), net had an unfavorable variance for the year ended December 31, 2011 mainly due to a $7.3 million loss recorded on the fair value revaluation of derivatives in 2011 as a result of higher prices plus $7.2 million unfavorable variance resulting from losses on cash settlements. We recognized a $20.6 million mark-to-market gain and a $5.4 million mark-to-market loss for derivatives, which were valued upon unobservable inputs, for the year ended December 31, 2011 and 2010, respectively.

Non-cash linefill gain (loss) had an unfavorable variance for the year ended December 31, 2011 compared to the prior year period primarily due to a decreased gain recognized on the revaluation of linefill due to decreased linefill volumes for the year ended December 31, 2011 as a result of the settlement of the linefill related to the Velma gas plant.

Equity income in joint ventures increased for the year ended December 31, 2011, primarily due to $4.6 million in equity earnings generated in the current period from our 20% ownership interest in WTPLG, which was purchased in May 2011, which was offset by $4.5 million in lower equity earnings from Laurel Mountain, due to the sale of our ownership interest on February 17, 2011 (see Dispositions).

Gain (loss) on asset sales and other for the years ended December 31, 2011 and 2010 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011 (see Dispositions).

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. Loss on early extinguishment of debt for the year ended December 31, 2010 represents the accelerated amortization of debt expense related to the early retirement of our term loan with proceeds from the sale of Elk City (see Dispositions).

Income from discontinued operations for the year ended December 31, 2010 represents a $312.1 million gain on sale associated with the Elk City system, which was sold on September 16, 2010, and $9.1 million net income related to the operations of Elk City (see Dispositions).

Income attributable to non-controlling interests increased primarily due to higher net income for the WestOK and WestTX joint ventures, which were formed to accomplish our acquisition of control of the systems. The increase in net income of the joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher prices and volumes. The non-controlling interest expense represents Anadarko s interest in the net income of the WestOK and WestTX joint ventures.

Table of Contents

Non-GAAP financial data:

EBITDA was lower for the year ended December 31, 2011 compared to the prior year period due to the gain on sale of discontinued operations of $312.1 million recognized during the year ended December 31, 2010, as discussed above in Other income items ; partially offset by the $256.3 million gain on asset sales recognized during the year ended December 31, 2011, as discussed above in Other income items .

Adjusted EBITDA had an unfavorable variance for the year ended December 31, 2011 compared to the prior year period primarily due to $34.8 million Adjusted EBITDA recognized for the year ended December 31, 2010 related to the discontinued operations from Elk City, which was sold on September 16, 2010, as discussed above in Other income items.

Distributable cash flow had a favorable variance for the year ended December 31, 2011 compared to the prior year period mainly due to the favorable interest expense variance, as discussed above in Expenses.

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, 2012, we had $293.0 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 $306.9 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, 2012. We had a working capital deficit of $33.4 million at December 31, 2012 compared with a $39.5 million working capital deficit at December 31, 2011. 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

Table of Contents

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, 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,			Percent
	2012	2011	Variance	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 Recent Events); (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 (see Recent Events); (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 (see Recent Events); 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. 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.

Table of Contents

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

The following table details the variances between the years ended 2011 and 2010 for cash flows (in thousands):

	Years Ended December 31, 2011	Years Ended December 31, 2010	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 102,867	$ 106,427	$ (3,560)	(3.4)%
Investing activities	67,763	594,753	(526,990)	(88.6)%
Financing activities	(170,626)	(702,037)	531,411	75.7%
Net change in cash and cash equivalents	$ 4	$ (857)	$ 861	100.5%

Net cash provided by operating activities for the year ended December 31, 2011 decreased primarily due to a $42.4 million decrease in the change in working capital and a $23.4 million decrease in cash provided by discontinued operations; offset by a $62.2 million increase in net earnings from continuing operations excluding non-cash charges. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased revenues from the sale of natural gas and NGLs (see Results of Operations).

Net cash provided by investing activities for the year ended December 31, 2011 decreased mainly as a result of net proceeds of $676.8 million received from the sale of the Elk City system in the prior period (see Dispositions); a $199.7 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 $85.0 million paid for the acquisition of WTLPG; partially offset by $403.6 million net cash proceeds from the sale of Laurel Mountain (see Dispositions).

Net cash used in financing activities for the year ended December 31, 2011 decreased mainly due to a $433.5 million repayment of our term loan in the prior period; a $256.0 million reduction in the outstanding borrowings on our revolving credit facility in the prior period; $152.4 million proceeds received in the current period related to our issuance of 8.75% Senior Notes and a $72.0 million increase in the outstanding borrowings on our revolving credit facility in the prior period; partially offset by $293.9 million paid for the redemption of the 8.125% Senior Notes and a portion of the 8.75% Senior Notes in the current period and an $80.5 million increase in distributions paid to common limited partners, the General Partner and preferred limited partners. The proceeds from the sale of Elk City (see Dispositions) were utilized in the retirement of the term loan and the reduction in borrowings on the revolving credit facility in the prior year period. The proceeds from the sale of Laurel Mountain were utilized in the redemption of the Senior Notes in the current year period.

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.

Table of Contents

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

	Years Ended December 31,		
	2012	2011	2010
Maintenance capital expenditures	$ 19,021	$ 18,247	$ 10,921
Expansion capital expenditures	354,512	227,179	35,715
Total	$ 373,533	$ 245,426	$ 46,636

Expansion capital expenditures increased for the year ended December 31, 2012 compared to the prior year period primarily due to current major processing facility expansions, compressor upgrades and pipeline projects, including the 60 MMCFD expansion at the Velma system, which was placed in service in June 2012 (see Recent Events); a 200 MMCFD expansion at the WestOK system, placed in service in September 2012 (see Recent Events); and construction of a 200 MMCFD plant in the WestTX system scheduled to be placed in service in the first half of 2013. As of December 31, 2012, we had approved additional expenditures of approximately $263.6 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $101.3 million purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our existing revolving credit facility.

Expansion capital expenditures increased for year ended December 31, 2011 primarily due to major processing facility expansions, compressor upgrades and pipeline projects. The increase in maintenance capital expenditures for the year ended December 31, 2011 when compared with the prior year period was due to expanded processing and gathering facilities and increased volumes on these facilities.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our General Partner within 45 days following the end of each 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.

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 $6.3 million and $1.7 million were paid during the years ended December 31, 2012 and 2011, respectively. No incentive distributions were paid during the year ended December 31, 2010.

Table of Contents

Off Balance Sheet Arrangements

As of December 31, 2012, 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, 2012 (in thousands):

		Payments Due By Period			
	Total	Less than 1 Year	1 3 Years	4 5 Years	After 5 Years
Contractual cash obligations:					
Total debt	$ 1,158,822	$	$	$ 293,000	$ 865,822
Interest on total debt(1)	465,477	72,754	145,508	141,085	106,130
Capital leases	11,950	11,264	681	5	
Operating leases	16,308	3,935	7,447	3,326	1,600
Total contractual cash obligations(2)	$ 1,652,557	$ 87,953	$ 153,636	$ 437,416	$ 973,552

(1) Based on the interest rates of our respective debt components as of December 31, 2012.
(2) Excludes net non-current deferred tax liabilities of $40.5 million due to uncertainty of the timing of future cash flows for such liabilities.

		Amount of Commitment Expiration Per Period			
	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	101,337	101,337			
Throughput contracts	34,153	9,062	13,023	7,006	5,062
Total commercial commitments	$ 135,565	$ 110,474	$ 13,023	$ 7,006	$ 5,062

Common Equity Offerings

On January 7, 2010, we executed amendments to warrants, which were originally issued in August 2009, granting investors in our private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. The amendments to the warrants lowered the warrant exercise price to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million. On November 30, 2010, we received a capital contribution from the General Partner of $0.3 million for the General Partner to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and credit facility (see Revolving Credit Facility) and to fund the early termination of certain derivative agreements. See Item 8. Financial Statements and Supplementary Data Note 11 .

78

Table of Contents

In November 2012, we entered into an equity distribution program with Citigroup, through which we may offer and sell common units having an aggregate value of up to $150.0 million. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end and there will be no minimum purchase requirements. During the year ended December 31, 2012, we issued 275,429 common units under the equity distribution program for net proceeds of $8.7 million, including $0.2 million in commission paid to citigroup. We also received a capital contribution from the General Partner of $0.2 million to maintain its 2.0% general partner interest in us. The net proceeds were used for general partnership purposes (see Recent Events).

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 Recent Events).

Preferred Units

On June 30, 2010, we sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units) to Atlas Energy, Inc., for cash consideration of $1,000 per Class C Preferred Unit, for total proceeds of $8.0 million. Subsequently, on May 27, 2011, we redeemed the 8,000 Class C Preferred units for cash, at the liquidation value of $1,000 per unit, or $8.0 million, plus $0.2 million, representing the accrued dividends on the 8,000 Class C Preferred Units prior to our redemption.

In November 2012, we executed a unit purchase agreement for a private placement of $200 million of newly-created Class D convertible preferred units to third party investors. The unit purchase agreement was entered into to provide proceeds for the Cardinal Acquisition. 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 (see Recent Events).

Revolving Credit Facility

At December 31, 2012, we had a $600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. 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, 2012, was 2.6%. 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, 2012. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

On May 31, 2012, we entered into an amendment to the revolving credit facility agreement, which among other changes increased the revolving credit facility from $450.0 million to $600.0 million and extended the maturity date from December 22, 2015 to May 31, 2017 (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,

Table of Contents

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, 2012, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At December 31, 2012, we had $370.2 million principal amount outstanding of 8.75% Senior Notes and $505.2 million principal outstanding of 6.625% Senior Notes (with the 8.75% Senior Notes, the Senior Notes).

The 8.75% Senior Notes are presented combined with a net $4.4 million unamortized premium as of December 31, 2012. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

The 6.625% Senior Notes are presented combined with a net $5.2 million unamortized premium as of December 31, 2012. 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 April 7, 2011, we redeemed $7.2 million of the 8.75% Senior Notes, which were tendered upon our offer to purchase the 8.75% Senior Notes, at par. The sale of our 49% non-controlling interest in Laurel Mountain on February 17, 2011 (see Dispositions) constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, we offered to purchase any and all of the 8.75% Senior Notes.

On April 8, 2011, we redeemed all of 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. We paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. In addition, we recorded $5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of the 8.125% Senior Notes and a partial redemption of the 8.75% Senior Notes.

On November 21, 2011, we 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%. We received net proceeds of $152.4 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on our revolving credit facility.

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 (see Recent Events).

Table of Contents

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 $176.5 million and utilized the proceeds to partially finance the Cardinal Acquisition (see Recent Events).

In connection with the issuance of the 6.625% Senior Notes on September 28, 2012 and December 20, 2012, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013 in the case of the 6.625% Senior Notes issued in September, or by December 15, 2013, in the case of the 6.625% Senior Notes issued in December. If we do not meet the aforementioned deadline, the 6.625% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that we cause the exchange offer to be consummated.

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.

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, 2012.

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.

Table of Contents

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, 2012, 2011 and 2010. While we anticipate inflation may affect our future operating costs, we cannot predict the timing or amounts of any such effects.

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, 2012:

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, 2012, there were $100.8 million accrued unbilled revenues. A 10% change in the estimated revenues would change gross margin by approximately $2.0 million.

Table of Contents

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
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 loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset.	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 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.	As of December 31, 2012, there were no indicators of impairment for any of our 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 asset.
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.	Due to the recent acquisition of reporting units with goodwill occurring during the year ended December 31, 2012, there were no indicators that it was more likely than not that the carrying value of a reporting unit exceeded its fair value, based on the qualitative analysis performed. We recorded no impairment to goodwill for the year ended December 31, 2012.
Depreciation		
Depreciation expense is generally computed using the straight-line method over the estimated useful life of the assets.	Determination of depreciation expense requires judgment regarding the estimated useful lives and salvage values of property, plant and equipment. As circumstances warrant, depreciation estimates are reviewed to determine if any changes in the underlying assumptions are necessary.	The life of our long-lived assets ranges from 2 40 years. If the depreciable lives of our assets were decreased by 10%, we estimate that annual depreciation expense would increase by approximately $11.5 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
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, 2012, approximately 74% of our derivatives are classified as Level 3 with the remainder 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 $31.0 million and $16.5 million net derivative assets at December 31, 2012 and 2011, respectively, we had $23.1 million and $16.5 million net derivative assets at December 31, 2012 and 2011, 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, 2012 would have resulted in approximately a $9.9 million noncash change to net income for the year ended December 31, 2012.
Income Taxes		
Our corporate subsidiary acquired in the Cardinal Acquisition (see Recent Events) accounts for income taxes under the asset and liability method. (See Item 8. Financial Statements and Supplementary Data Note 10 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 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.	As of December 31, 2012, we have recorded deferred tax assets of $10.3 million. A 10% adjustment due to a valuation allowance related to the realization of deferred assets could result in an approximately $1.0 million impact on net earnings.

Table of Contents

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.

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, 2012. 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, 2012, we had a $600.0 million senior secured revolving credit facility with $293.0 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 2.6% at December 31, 2012. 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 $2.9 million.

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 January 2, 2013, were $0.91 per gallon, $3.45 per million BTU and $94.16 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended December 31, 2013 by approximately $13.5 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, 2012 and 2011, and the related consolidated statements operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 28, 2013

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,398	$ 168
Funds held in escrow	25,000	
Accounts receivable	157,526	115,412
Current portion of derivative assets	23,077	1,645
Prepaid expenses and other	11,074	15,641
Total current assets	220,075	132,866
Property, plant and equipment, net	2,200,381	1,567,828
Goodwill	319,285	
Intangible assets, net	199,360	103,276
Equity method investment in joint venture	86,002	86,879
Long-term portion of derivative assets	7,942	14,814
Other assets, net	32,593	25,149
Total assets	$ 3,065,638	$ 1,930,812
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 10,835	$ 2,085
Accounts payable affiliates	5,500	2,675
Accounts payable	59,308	54,644
Accrued liabilities	57,752	23,282
Accrued interest payable	10,399	1,624
Accrued producer liabilities	109,725	88,096
Total current liabilities	253,519	172,406
Long-term debt, less current portion	1,169,083	522,055
Deferred income taxes, net	30,258	
Other long-term liability	6,370	123
Commitments and contingencies		
Equity:		
General Partner s interest	31,501	23,856
Common limited partners interests	1,507,676	1,245,163
Accumulated other comprehensive loss		(4,390)
Total partners capital	1,539,177	1,264,629
Non-controlling interest	67,231	(28,401)
Total equity	1,606,408	1,236,228
Total liabilities and equity	$ 3,065,638	$ 1,930,812

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		
	2012	**2011**	**2010**
Revenue:			
Natural gas and liquids sales	$ 1,137,261	$ 1,268,195	$ 890,048
Transportation, processing and other fees third parties	66,287	43,464	40,474
Transportation, processing and other fees affiliates	435	335	619
Derivative gain (loss), net	31,940	(20,452)	(5,945)
Other income, net	10,097	11,192	10,392
Total revenues	1,246,020	1,302,734	935,588
Costs and expenses:			
Natural gas and liquids cost of sales	927,946	1,047,025	720,215
Plant operating	60,480	54,686	48,670
Transportation and compression	1,618	833	1,061
General and administrative	43,406	34,551	32,521
Compensation reimbursement affiliates	3,800	1,806	1,500
Other costs	15,069	1,040	
Depreciation and amortization	90,029	77,435	74,897
Interest	41,760	31,603	87,273
Total costs and expenses	1,184,108	1,248,979	966,137
Equity income in joint ventures	6,323	5,025	4,920
Gain (loss) on asset sale and other		256,272	(10,729)
Loss on early extinguishment of debt		(19,574)	(4,359)
Income (loss) from continuing operations before tax	68,235	295,478	(40,717)
Income tax expense	176		
Income (loss) from continuing operations	68,059	295,478	(40,717)
Discontinued operations:			
Gain (loss) on sale of discontinued operations		(81)	312,102
Earnings from discontinued operations			9,053
Income (loss) from discontinued operations net of tax		(81)	321,155
Net income	68,059	295,397	280,438
Income attributable to non-controlling interests	(6,010)	(6,200)	(4,738)
Preferred unit dividends		(389)	(780)
Net income attributable to common limited partners and the General Partner	$ 62,049	$ 288,808	$ 274,920

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31		
	2012	**2011**	**2010**
Allocation of net income (loss) attributable to:			
Common limited partner interest:			
Continuing operations	$ 52,391	$ 281,449	$ (45,347)
Discontinued operations		(79)	315,021
	52,391	281,370	269,674
General Partner interest:			
Continuing operations	9,658	7,440	(888)
Discontinued operations		(2)	6,134
	9,658	7,438	5,246
Net income (loss) attributable to:			
Continuing operations	62,049	288,889	(46,235)
Discontinued operations		(81)	321,155
	$ 62,049	$ 288,808	$ 274,920
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ 0.95	$ 5.22	$ (0.85)
Discontinued operations			5.92
	$ 0.95	$ 5.22	$ 5.07
Weighted average common limited partner units (basic)	54,326	53,525	53,166
Diluted:			
Continuing operations	$ 0.95	$ 5.22	$ (0.85)
Discontinued operations			5.92
	$ 0.95	$ 5.22	$ 5.07
Weighted average common limited partner units (diluted)	55,138	53,944	53,166

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net income	$ 68,059	$ 295,397	$ 280,438
Income attributable to non-controlling interests	(6,010)	(6,200)	(4,738)
Preferred unit dividends		(389)	(780)
Net income attributable to common limited partners and the General Partner	62,049	288,808	274,920
Other comprehensive income:			
Adjustment for realized losses reclassified to net income	4,390	6,834	37,966
Comprehensive income	$ 66,439	$ 295,642	$ 312,886

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

	Number of Limited Partner Units		Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Preferred Units of Atlas Pipeline Holdings II, LLC	Non-controlling Interest	Total
	Preferred	Common							
Balance at January 1, 2010	15,000	50,517,103	$ 14,955	$ 787,834	$ 15,853	$ (49,190)	$ (15,000)	$ (30,925)	$ 723,527
Redemption of preferred limited partner units	(15,000)		(14,955)	(45)					(15,000)
Redemption of treasury units							15,000		15,000
Issuance of units and General Partner capital contribution	8,000	2,689,765	8,000	15,319	(670)				22,649
Issuance of common units under incentive plans		151,584		156					156
Purchase and retirement of common limited partner units		(20,442)		(246)					(246)
Unissued common units under incentive plans				3,484					3,484
Distributions paid			(3,167)	(18,834)	(363)		2,627		(19,737)
Distribution payable			(240)						(240)
Distributions paid to non-controlling interests								(6,350)	(6,350)
Other comprehensive income						37,966			37,966
Net income			3,407	269,674	5,246		(2,627)	4,738	280,438
Balance at December 31, 2010	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 paid 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 General Partner capital contribution	10,782,462		321,491	6,865				328,356
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
Increase in non-controlling interest due to business combination							89,440	89,440
Distributions paid			(122,223)	(8,878)				(131,101)
Distributions received from non-controlling interests							182	182
Other comprehensive income					4,390			4,390
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

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, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 68,059	$ 295,397	$ 280,438
Less: Income (loss) from discontinued operations		(81)	321,155
Net income (loss) from continuing operations	68,059	295,478	(40,717)
Adjustments to reconcile net income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	90,029	77,435	74,897
Equity income in joint ventures	(6,323)	(5,025)	(4,920)
Distributions received from equity method joint ventures	7,200	4,448	11,066
Non-cash compensation expense	11,635	3,274	3,484
Amortization of deferred finance costs	4,672	4,480	6,186
Deferred income tax expense	176		
(Gain) loss on asset sales		(256,272)	2,229
Loss on early extinguishment of debt		19,574	4,359
Change in operating assets and liabilities:			
Accounts receivable, prepaid expenses and other	(31,417)	(16,216)	(21,498)
Accounts payable and accrued liabilities	37,952	5,093	32,906
Accounts payable and accounts receivable affiliates	2,825	(9,605)	10,237
Derivative accounts payable and receivable	(10,170)	(19,797)	4,824
Net cash provided by continuing operating activities	174,638	102,867	83,053
Net cash provided by discontinued operating activities			23,374
Net cash provided by operating activities	174,638	102,867	106,427
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(373,533)	(245,426)	(45,752)
Capital contribution to joint ventures		(12,250)	(26,514)
Cash paid for business combinations, net of cash received	(633,610)	(85,000)	
Proceeds from preferred rights to note receivable		8,500	
Net proceeds (expenditures) related to asset sales		403,578	(2,229)
Other	502	(1,558)	56
Net cash provided by (used in) continuing investing activities	(1,006,641)	67,844	(74,439)
Net cash provided by (used in) discontinued investing activities		(81)	669,192
Net cash (used in) provided by investing activities	(1,006,641)	67,763	594,753
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	1,170,500	1,515,500	482,000
Repayments under credit facility	(1,019,500)	(1,443,500)	(738,000)
Net proceeds from issuance of long term debt	495,374	152,366	
Repayment of long term debt		(279,557)	(433,505)
Payment of premium on early retirement of debt		(14,342)	
Payments of deferred financing costs associated with credit facility	(4,542)		

Principal payments on capital lease	(2,523)	(954)	(142)
Net proceeds from issuance of common limited partner units	321,491	468	15,475
Purchase and retirement of treasury units	(695)	(984)	(246)
Net proceeds from issuance of preferred limited partner units			8,000
Redemption of preferred limited partner units		(8,000)	(15,000)
Redemption of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC			15,000
General Partner capital contributions	6,865		331
Net distributions received from (paid to) non-controlling interest holders	182	(2,064)	(6,350)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(131,101)	(100,313)	(19,737)
Other	(818)	10,754	(9,863)
Net cash provided by (used in) financing activities	835,233	(170,626)	(702,037)
Net change in cash and cash equivalents	3,230	4	(857)
Cash and cash equivalents, beginning of period	168	164	1,021
Cash and cash equivalents, end of period	$ 3,398	$ 168	$ 164

See accompanying notes to consolidated financial statements

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, 2012, 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, 2012, the Partnership had 64,556,010 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS.

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 also 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. 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 ventures as a component of equity on its consolidated balance sheets. The 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 WestTX joint venture has a 72.8% undivided joint venture 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.

The Partnership s consolidated financial statements also include its 60% interest in Centrahoma Processing LLC (Centrahoma), which was acquired on December 20, 2012 as part of the Cardinal Acquisition (see Note 3). 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 this joint venture 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 ventures as a component of equity on its consolidated balance sheets.

95

Table of Contents

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 on February 17, 2011 (see Note 4); and its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) after its acquisition on May 11, 2011 (see Note 4). The Partnership accounts for its investment in the joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures net income 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 amortized but is evaluated for impairment, annually. This 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 or WTLPG. Equity method investments are subject to impairment evaluation. The Partnership evaluated its investment in WTLPG as of December 31, 2012 and determined there was no impairment of the investment.

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 believes the operating results presented represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

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 are considered to be accounts payable. At December 31, 2012 and 2011, the Partnership reclassified balances related to outstanding checks of $27.6 million and $26.2 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, 2012 and 2011, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

NGL Linefill

The Partnership had $7.8 million and $11.5 million of NGL linefill at December 31, 2012 and 2011, 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.

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 lives of an asset for two or more years through the replacement of critical components are capitalized. 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 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.

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 rate used to capitalize interest on borrowed funds was 6.4%, 7.0% and 7.5% for the years ended December 31, 2012, 2011 and 2010, respectively. The amount of interest capitalized was $8.7 million, $5.1 million and $0.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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. 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 14). 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 that the carrying amount of an asset may not be recoverable. If it is determined that an asset s estimated future 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 estimated fair value is determined utilizing a market approach, based upon the value a third party would be willing to pay for the assets in use and thus would be considered a Level 1 input (see Fair Value of Financial Instruments). No impairment charges were recognized for the years ended December 31, 2012, 2011 and 2010.

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, 2012 or 2011 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. The Partnership evaluates goodwill for impairment annually, on December 31, 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 Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is 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 on December 31, 2012 and determined that due to the recent acquisition of the goodwill and no substantive changes during the current year that there was no indication of impairment. Thus, no quantitative analysis was performed for the year ended December 31, 2012. No goodwill impairments charges were recognized for the years ended December 31, 2012, 2011 and 2010 (see Note 8).

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 8).

Table of Contents

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 as of December 31, 2012.

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 12). 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, 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 2009. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2012 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, 2011.

APL Arkoma, Inc., a corporate subsidiary acquired through the Cardinal Acquisition (see Note 3) 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 10 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.

Table of Contents

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% general partner interest and incentive distributions to be distributed for the quarter (see Note 6), 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.

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 17), 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. As such, 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.

Table of Contents

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):

	Years Ended December 31,		
	2012	2011	2010
Continuing operations:			
Net income (loss)	$ 68,059	$ 295,478	$ (40,717)
Income attributable to non-controlling interests	(6,010)	(6,200)	(4,738)
Preferred unit dividends		(389)	(780)
Net income (loss) attributable to common limited partners and the General Partner	62,049	288,889	(46,235)
General Partner s cash incentive distributions declared	8,583	1,666	
General Partner s ownership interest	1,075	5,774	(888)
Net income (loss) attributable to the General Partner s ownership interests	9,658	7,440	(888)
Net income (loss) attributable to common limited partners	52,391	281,449	(45,347)
Net income attributable to participating securities phantom units[(1)]	772	2,187	
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ 51,619	$ 279,262	$ (45,347)
Discontinued operations:			
Net income (loss)	$	$ (81)	$ 321,155
Net income (loss) attributable to the General Partner s ownership interests		(2)	6,134
Net income (loss) utilized in the calculation of net income (loss) from discontinued operations attributable to common limited partners per unit	$	$ (79)	$ 315,021

(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). For the year ended December 31, 2010, net loss attributable to common limited partners ownership interest is not allocated to approximately 300,000 phantom units, because the contractual terms of the phantom 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 and unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plans (see Note 17).

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,		
	2012	2011	2010
Weighted average number of common limited partner units basic	54,326	53,525	53,166
Add effect of participating securities phantom units[1]	812	419	
Add effect of dilutive option incentive awards[2]			
Weighted average common limited partner units diluted	55,138	53,944	53,166

(1) For the year ended December 31, 2010, approximately 300,000 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, 2010, 75,000 unit options 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. There were no unit options outstanding for the years ended December 31, 2012 and 2011.

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, 2012 and 2011, 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 Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma 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 contract 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.

Table of Contents

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. 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.

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 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 (see Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at December 31, 2012 and 2011 of $100.8 million and $68.6 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Table of Contents

Recently Adopted Accounting Standards

In May 2011, the FASB issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, which, among other changes, requires (1) additional disclosures for fair value measurements categorized within Level 2 and Level 3 of the fair value hierarchy; and (2) additional disclosures for items not measured at fair value in the Partnership s consolidated balance sheets but for which the fair value is required to be disclosed. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. The Partnership updated its disclosures to meet these requirements upon the adoption of this ASU on January 1, 2012 (see Note 12). The adoption had no material impact on the Partnership s financial position or results of operations.

In June 2011, the FASB issued ASU 2011-05, Comprehensive Income (Topic 220) Presentation of Comprehensive Income, which, among other changes, eliminates the option to present components of other comprehensive income as part of the statement of changes in equity. In December 2011, the FASB issued ASU 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05, which supersedes the requirements in ASU 2011-05 pertaining to how, when and where reclassifications out of accumulated other comprehensive income are presented on the face of the financial statements and reinstates the requirements for the presentation of reclassifications out of accumulated other comprehensive income that were in place before the issuance of ASU 2011-05. The amendments in these updates require all non-owner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The updates do 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, 2011. The Partnership began including consolidated statements of comprehensive income within its Form 10-Qs upon the adoption of these ASUs on January 1, 2012. The adoption had no material impact on the Partnership s financial position or results of operations.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, which requires an entity to disclose additional information regarding offsetting arrangements for derivative instruments that are presented as net balances within its financial statements. Entities are required to implement the amendments for interim and annual reporting periods beginning after January 1, 2013 and apply them retrospectively for any period presented that begins before the date of initial application. The Partnership elected to adopt these requirements early and updated its disclosures to meet these requirements effective January 1, 2012 (see Note 11). The adoption had no material impact on the Partnership s financial position or results of operations.

NOTE 3 ACQUISITIONS

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 $598.5 million in cash, including preliminary purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas as follows:

- the Tupelo plant, which is a 120 MMCFD cryogenic processing facility;

- approximately 60 miles of gathering pipeline;

105

- the East Rockpile treating facility;
- a fixed fee contract gas treating business that includes fifteen amine treating plants and two propane refrigeration plants; and
- a 60% interest in Centrahoma, which owns the following assets:
  - the Coalgate and Atoka plants, which are cryogenic processing facilities with current processing capacity of approximately 100 MMCFD;
  - the prospective Stonewall plant, for which construction has been approved, with processing capacity of 120 MMCFD; and
  - 15 miles of NGL pipeline.

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

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 2020 (6.625% Senior Notes) at a premium of 3.0%, for net proceeds of $176.5 million (see Note 14); 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 6). The Partnership funded the remaining purchase price from its senior secured revolving credit facility (see Note 14).

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 the acquisition, the accounting for the business combination has not been completed. The estimates of fair value reflected as of December 31, 2012 are subject to change and changes could be material. Revisions to these estimates will be recorded retrospectively during the measurement period of one year from the acquisition date of December 20, 2012.

Table of Contents

The following table presents the preliminary values assigned to the assets acquired and liabilities assumed in the Cardinal Acquisition, based on their estimated fair values at the date of the acquisition, including the 40% non-controlling interest of Centrahoma held by MarkWest (in thousands):

Cash	$ 3,246
Accounts receivable	19,618
Prepaid expenses and other	1,377
Property, plant and equipment	295,855
Intangible assets contracts	107,530
Goodwill	310,904
Total assets acquired	738,530
Current portion of long-term debt	(341)
Accounts payable and accrued liabilities	(16,496)
Deferred tax liability, net	(30,082)
Long-term debt, less current portion	(604)
Total liabilities acquired	(47,523)
Non-controlling interest	(89,310)
Net assets acquired	**601,697**
Less cash received	(3,246)
Net cash paid for acquisition	**$ 598,451**

The fair value of MarkWest s 40% non-controlling interest in Centrahoma was determined based upon the purchase price allocated to the 60% controlling interest the Partnership acquired.

In conjunction with the issuance of the Partnership s common limited partner units associated with the acquisition, $12.2 million of transaction fees were included in the $319.3 million net proceeds recorded within common limited partners interests on the Partnership s consolidated balance sheets. In conjunction with the issuance of debt, $4.8 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 $15.4 million associated with the Cardinal Acquisition were expensed as incurred and recorded to other costs on the Partnership s consolidated statements of operations.

Revenues and net earnings of $8.5 million and $1.0 million, respectively, have been included in the Partnership s consolidated financial statements related to the Cardinal Acquisition for the year ended December 31, 2012, of which $8.3 million and $0.9 million of revenues and net earnings, respectively, were included in the Partnership s Gathering and Processing operating segment. Revenues and net earnings of $0.2 million and $0.1 million, respectively, are included in the Partnership s Transportation and Treating operating segment for the year ended December 31, 2012. Net earnings of $1.7 million contributed from the Cardinal Acquisition from December 1, 2012 (the effective date) to December 20, 2012 (the closing date) were included in the purchase price adjustment.

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, 2012 and 2011 as if (1) the Cardinal Acquisition; (2) the equity offering for net proceeds of $319.3 million in December 2012, including General Partner contribution; (3) the $176.5 million net proceeds from the 6.625% Senior Notes; and (4) the borrowings under the Partnership s revolving credit facility had been included in operations commencing on January 1, 2011 (in thousands, except per unit data; unaudited):

	Years Ended December 31,	
	2012(1)	**2011(1)**

Total revenues	$ 1,514,223	$ 1,549,457
Continuing net income attributable to common limited partners and the General Partner	74,817	258,020
Continuing net income attributable to common limited partner unit:		
Basic and diluted	$ 1.00	$ 3.90

(1) Pro forma earnings for the year ended December 31, 2012 were adjusted to exclude $15.4 million of acquisition-related costs incurred and pro forma earnings for the year ended December 31, 2011 were adjusted to include these costs.

Table of Contents

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 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 IN JOINT VENTURES

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 $254.1 million. The Partnership recognized a $256.3 million gain during the year ended December 31, 2011 and a $2.2 million loss during the year ended December 31, 2010 for expenses related to the sale. 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 (see Note 14) and for general company purposes.

During the year ended December 31, 2010 the Partnership made cash payments of $26.5 million for capital contributions to Laurel Mountain.

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 a $25.5 million note receivable due from Williams. During the years ended December 31, 2010 and 2009, the Partnership utilized $15.3 million and $1.7 million, respectively, of the note receivable for capital contributions to Laurel Mountain. In December 2011, Williams made cash payment to the Partnership to settle the $8.5 million 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.

The following table summarizes the components of equity income on the Partnership s statements of operations (in thousands).

	Years Ended December 31,		
	2012	**2011**	**2010**
Equity income in Laurel Mountain	$	$ 462	$ 4,920
Equity income in WTLPG	6,323	4,563	
Equity income in joint ventures	$ 6,323	$ 5,025	$ 4,920

NOTE 5 DISCONTINUED OPERATIONS

On September 16, 2010, the Partnership completed the sale of its Elk City and Sweetwater, Oklahoma natural gas gathering systems, and the related processing and treating facilities (including the Prentiss treating facility and the Nine Mile processing plant, collectively Elk City) to a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) for $682.0 million in cash, excluding working capital adjustments and transaction costs. The Partnership recognized a gain of $312.1 million on the sale of Elk City within income from discontinued operations on its consolidated statements of operations, during the year ended December 31, 2010. During the year ended December 31, 2011, the Partnership recorded, within its consolidated statements of operations, a reduction to the gain on sale of Elk City of $81 thousand to recognize the final settlement of working capital adjustments and transaction costs. The Partnership accounted for the earnings of Elk City as discontinued operations within its consolidated financial statements. Elk City was previously included within the Partnership s formerly reported Mid-Continent segment of operations, which was reclassified to the Partnership s current Gathering and Processing segment of operations (see Note 19).

Table of Contents

The following table summarizes the components included within income from discontinued operations on the Partnership s consolidated statements of operations (in thousands):

	Years Ended December 31, 2011	2010
Total revenues	$	$ 129,908
Total costs and expenses		(120,855)
Earnings from discontinued operations		9,053
Gain (loss) on asset sales and other	(81)	312,102
Total income (loss) from discontinued operations	$ (81)	$ 321,155

The Partnership s continuing operations include $18.0 million within natural gas and liquids sales on the consolidated statements of operations for the year ended December 31, 2010 for intercompany sales from the WestOK system to Elk City. These intercompany sales were previously eliminated in consolidation prior to the sale of Elk City and were reinstated within natural gas and liquids sales from continuing operations upon the sale of Elk City. In the periods subsequent to the sale of Elk City, these sales have been made directly to third parties.

NOTE 6 EQUITY

Common Units

In August 2009, the Partnership issued warrants granting investors the right to purchase 2,689,765 common units at a price of $6.35 per unit. In January 2010, the Partnership executed amendments to the warrants in which, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million to the Partnership. The Partnership utilized the net proceeds from the common unit offering to repay a portion of its indebtedness under its senior secured term loan (see Note 14) and to fund the early termination of certain derivative agreements (see Note 11).

In March 2010, the Partnership and the Operating Partnership amended their respective partnership agreements to temporarily waive the requirement that the General Partner make aggregate cash contributions of approximately $0.3 million, which was required in connection with the Partnership s issuance of 2,689,765 of its common units upon the exercise of warrants in January 2010. The waiver remained in effect until the General Partner made the required capital contribution on November 30, 2010. During the waiver period, the aggregate ownership percentage attributable to General Partner s general partner interest in the Partnership was reduced to 1.9%.

In November 2012, the Partnership entered into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership may offer and sell from time to time through Citigroup, as its sales agent, common units having an aggregate value of up to $150.0 million. Subject to the terms and conditions of the equity distribution agreement, Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end; there will be no minimum purchase requirements; and there will be no arrangements to place the proceeds of the offering in an escrow, trust or similar account. Under the terms of the equity distribution agreement, the Partnership also may sell common units to Citigroup as principal for its own account at a price agreed upon at the time of the sale. The Partnership intends to use the net proceeds from any such offering for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. Amounts repaid under the Partnership s revolving credit facility may be reborrowed to fund ongoing capital programs, potential future acquisitions or for general partnership purposes. During the year ended December 31, 2012, the Partnership issued 275,429 common units under the equity distribution program for net proceeds of $8.7 million, including $0.2 million in commission paid to Citigroup. The Partnership also received a capital contribution from the General Partner of $0.2 million 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.

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. The Partnership utilized the net proceeds from the common unit offering to partially finance the Cardinal Acquisition (see Note 3).

Class B Preferred Units

On November 15, 2010, the Partnership redeemed 15,000 units of Class B Preferred Units for cash at the liquidation value of $1,000 per unit, or $15.0 million, plus $0.2 million, representing the quarterly dividend on the 15,000 Class B Preferred Units prior to the Partnership s redemption. There are no Class B Preferred Units outstanding. The Partnership recognized $2.9 million of preferred dividend cost for the years ended December 31, 2010, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations.

Class C Preferred Units

On June 30, 2010, the Partnership sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units) to AEI for cash consideration of $1,000 per Class C Preferred Unit (the Class C Preferred Unit Face Value) for net proceeds of $8.0 million. The Class C Preferred Units were entitled to receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership s common units. The Class C Preferred Units were not convertible into common units of the Partnership. The Partnership had the right at any time to redeem some or all of the outstanding Class C Preferred Units for cash at an amount equal to the Class C Preferred Face Value being redeemed plus accrued but unpaid dividends.

On February 17, 2011, as part of the Chevron Merger (see Note 4), Chevron acquired 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 and $0.5 million of preferred dividends for the years ended December 31, 2011 and 2010, respectively, 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 executed a unit purchase agreement for a private placement of $200.0 million of newly-created Class D convertible 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.

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 and 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% 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, 2009 through September 30, 2012 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, 2009	None	0.00		
March 31, 2010	None	0.00		
June 30, 2010	None	0.00		
September 30, 2010	November 14, 2010	0.35	18,660	363
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

On January 23, 2013, the Partnership declared a cash distribution of $0.58 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2012. The $40.6 million distribution, including $3.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013.

Table of Contents

NOTE 7 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 14) (in thousands):

	December 31, 2012	December 31, 2011	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,294,024	$ 1,615,015	2 40
Rights of way	178,234	161,191	20 40
Buildings	8,224	8,047	40
Furniture and equipment	10,305	9,392	3 7
Other	14,761	14,029	3 10
	2,505,548	1,807,674	
Less accumulated depreciation	(305,167)	(239,846)	
	$ 2,200,381	$ 1,567,828	

The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 14), of $66.2 million, $54.3 million and $51.8 million for the years ended December 31, 2012, 2011 and 2010, respectively, on its consolidated statements of operations.

As a result of the Cardinal Acquisition (see Note 3), 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: 2013 - $4.5 million; 2014 - $2.9 million; 2015 - $0.6 million; 2016-2017 - none.

NOTE 8 GOODWILL AND INTANGIBLE ASSETS

The Partnership recorded goodwill of $319.3 million in connection with the Cardinal Acquisition (see Note 3) and other acquisitions during the year ended December 31, 2012. The goodwill related to the Cardinal Acquisition is a result of the strategic industry position and potential future synergies (see Goodwill in Note 2). The Partnership estimates approximately $290.6 million of goodwill recorded as a result of the Cardinal Acquisition to be deductible for tax purposes. There was no goodwill recorded for the years ended December 31, 2011 and 2010.

The Partnership has recorded intangible assets with finite lives in connection with the Cardinal Acquisition (see Note 3) and other acquisitions of various gas gathering systems and related assets during the year ended December 31, 2012. The Partnership accounted for these acquisitions as business combinations and recognized $119.9 million related to customer contracts with an estimated useful life of 10-14 years. Due to the recent date of the Cardinal Acquisition, the accounting for the business combination has not been completed. The estimates of fair value reflected as of December 31, 2012 are subject to change and changes could be material. Revision to these estimates will be recorded retrospectively.

Table of Contents

The following table reflects the components of intangible assets being amortized at December 31, 2012 and 2011 (in thousands):

	December 31, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 119,933	$	10-14
Customer relationships	205,313	205,313	7 10
	325,246	205,313	
Accumulated amortization:			
Customer contracts	(746)		
Customer relationships	(125,140)	(102,037)	
	(125,886)	(102,037)	
Net carrying amount:			
Customer contracts	119,187		
Customer relationships	80,173	103,276	
Net carrying amount	$ 199,360	$ 103,276	

The weighted-average amortization period for customer contracts and customer relationships is 9.9 years and 9.1 years, respectively. The Partnership recorded amortization expense on intangible assets of $23.8 million, $23.1 million and $23.1 million for the years ended December 31, 2012, 2011 and 2010, 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: 2013 - $35.6 million; 2014 - $32.0 million; 2015 - $27.0 million; 2016 - $26.5 million; 2017 - $20.2 million.

NOTE 9 OTHER ASSETS

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

	December 31, 2012	December 31, 2011
Deferred finance costs, net of accumulated amortization of $23,536 and $18,864 at December 31, 2012 and 2011, respectively	$ 30,496	$ 20,750
Security deposits	2,097	4,399
	$ 32,593	$ 25,149

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 14). During the years ended December 31, 2012, 2011 and 2010, the Partnership incurred $14.4 million, $4.2 million and $9.8 million deferred finance costs, respectively, related to various financing activities (see Note 14). During the years ended December 31, 2011 and 2010, the Partnership recorded $5.2 million and $4.4 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 statements 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 $4.7 million, $4.5 million and $6.2 million for the years ended December 31, 2012, 2011 and 2010, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to remaining deferred finance costs is estimated to be as follows for each of the next five calendar years: 2013 to 2016 - $4.7 million per year; 2017 - $2.7 million.

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 (see Note 22). The Partnership estimates $5.4 million of accelerated amortization of deferred financing costs associated with the retirement of debt to be recorded in 2013, related to the retirement of the 8.75% Senior Notes.

Table of Contents

NOTE 10 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 expense of the Partnership s taxable subsidiary are summarized as follows:

	Year Ended December 31, 2012
Deferred expense:	
Federal	$ 158
State	18
Total income tax expense	$ 176

As of December 31, 2012, the Partnership had non-current net deferred income tax liabilities of $30.3 million. The components of net deferred tax liabilities for the year ended December 31, 2012 consist of the following:

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

The Partnership had net operating loss carry forwards for federal income tax purposes of approximately $26.3 million, which expire at various dates from 2029 and 2032. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 11 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.

Table of Contents

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 loss, within equity on the Partnership s consolidated balance sheets as of December 31, 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 assets on its consolidated balance sheets of $31.0 million and $16.5 million at December 31, 2012 and 2011, respectively.

The following table summarizes 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):

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Offsetting of Derivative Assets			
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
As of December 31, 2011			
Current portion of derivative assets	$ 11,603	$ (9,958)	$ 1,645
Long-term portion of derivative assets	17,011	(2,197)	14,814
Total derivative assets, net	$ 28,614	$ (12,155)	$ 16,459

Table of Contents

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Offsetting of Derivative Liabilities			
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	$
As of December 31, 2011			
Current portion of derivative liabilities	$ (9,958)	$ 9,958	$
Long-term portion of derivative liabilities	(2,197)	2,197	
Total derivative liabilities, net	$ (12,155)	$ 12,155	$

The following table summarizes the Partnership s commodity derivatives as of December 31, 2012, (fair value dollars and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed price swaps				
2013	Natural gas	1,200	$ 3.48	$ (51)
2014	Natural gas	5,400	3.90	(689)
2013	NGLs	54,936	1.26	14,961
2014	NGLs	29,610	1.31	1,286
2015	NGLs	2,520	1.97	567
2013	Crude oil	345	97.17	1,381
2014	Crude oil	210	92.08	(27)
Total fixed price swaps				17,428
Options				
Purchased put options				
2013	NGLs	38,556	1.94	6,269
2013	Crude oil	282	100.10	3,035
2014	Crude oil	332	95.74	4,287
Total options				13,591
Total derivatives				$ 31,019

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 12 for discussion on fair value methodology.

During the year ended December 31, 2010 the Partnership made net payments of $25.3 million related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through 2012. No contracts were terminated early during the years ended December 31, 2012 and 2011.

Table of Contents

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

		For the Years ended December 31, 2012	2011	2010
Loss Reclassified from Accumulated Other Comprehensive Loss into Income				
Contract Type	**Location**			
Interest rate contracts(1)	Interest expense	$	$	$ (2,242)
Commodity contracts(1)	Natural gas and liquids sales	(4,390)	(6,834)	(15,570)
Commodity contracts(1)	Discontinued operations			(20,154)
		$ (4,390)	$ (6,834)	$ (37,966)
Gain (Loss) Recognized in Income (Derivatives not designated as hedges)				
Location in consolidated statements of operations				
Derivative loss, net:				
Interest rate contract realized(1)(2)				(604)
Interest rate contract unrealized(1)(3)				598
Commodity contract - realized(2)		10,993	(13,123)	(5,890)
Commodity contract - unrealized(3)		20,947	(7,329)	(49)
Derivative loss, net		31,940	(20,452)	(5,945)
Discontinued operations:				
Commodity contract - realized(2)				(101)
Commodity contract - unrealized(3)				766
Discontinued operations				665
		$ 31,940	$ (20,452)	$ (5,280)

(1) Hedges previously designated as cash flow hedges.
(2) Realized gain (loss) represents the gain (loss) incurred when the derivative contract expires and/or is cash settled.
(3) Unrealized gain (loss) represents the mark-to-market gain (loss) recognized on open derivative contracts, which have not yet been settled.

NOTE 12 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 and NGL Linefill

At December 31, 2012, 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.

Table of Contents

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.

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, 2012 and 2011 (in thousands):

	Level 1	Level 2	Level 3	Total
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
December 31, 2011				
Assets				
Commodity swaps	$	$ 1,270	$ 1,836	$ 3,106
Commodity options		7,229	18,279	25,508
Total assets		8,499	20,115	28,614
Liabilities				
Commodity swaps		(2,766)	(3,569)	(6,335)
Commodity options		(5,820)		(5,820)
Total liabilities		(8,586)	(3,569)	(12,155)
Total derivatives	$	$ (87)	$ 16,546	$ 16,459

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, 2012 and 2011 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance January 1, 2011	32,760	$ (1,790)		$	$ (1,790)
New contracts[1]	58,002		110,796	28,187	28,187
Cash settlements from unrealized gain (loss)[2][3]	(41,118)	10,826	(18,186)	2,398	13,224
Net change in unrealized gain (loss)[2]		(10,769)		(9,875)	(20,644)
Deferred option premium recognition[3]				(2,431)	(2,431)
Balance December 31, 2011	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

(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 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, 2012 and 2011 (in thousands):

	Gallons	Third Party Quotes[1]	Adjustments[2]	Total Amount
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
As of December 31, 2011				
Ethane swaps	6,678	$ 31	$	$ 31
Propane swaps	29,358	(1,322)		(1,322)
Isobutane swaps	2,646	(1,590)	570	(1,020)
Normal butane swaps	6,804	(1,074)	343	(731)
Natural gasoline swaps	4,158	1,824	(515)	1,309
Total NGL swaps December 31, 2011	49,644	$ (2,131)	$ 398	$ (1,733)

(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 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, 2011				
Isobutane	$ 570	1.1239	1.1333	1.1286
Normal butane	343	1.0311	1.0355	1.0333
Natural gasoline	(515)	0.9351	0.9426	0.9389
Total Level 3 adjustments December 31, 2011	$ 398			
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)			

The Partnership had $7.8 million and $11.5 million of NGL linefill at December 31, 2012 and 2011, 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 is defined as a Level 3 asset and 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 $0.8 million as of December 31, 2012 and 2011, respectively.

The following table provides a summary of changes in fair value of the Partnership s NGL linefill for the years ended December 31, 2012 and 2011 (in thousands):

	NGL Linefill Gallons	Amount
Balance December 31, 2010	10,408	$ 10,622
Net change in NGL linefill valuation(1)		907
Balance December 31, 2011	10,408	$ 11,529
Cash settlements(1)	(2,520)	(2,698)
Net change in NGL linefill valuation(1)		(2,111)
Acquired NGL linefill(2)	1,260	1,063
Balance December 31, 2012	9,148	$ 7,783

(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 Acquisition (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). The fair value of the Trigger Payments recognized upon acquisition resulted in a $6.0 million current liability, which was recorded within accrued liabilities on the

Partnership s consolidated balance sheets, and a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership s consolidated balance sheets. Sufficient volumes were achieved in December 2012 and the Partnership paid the first Trigger Payment of $6.0 million in January 2013. The range of the undiscounted amounts the Partnership could pay related to the Trigger Payments is between $6.0 and $12.0 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 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, 2012 and 2011, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,216.4 million and $537.3 million, respectively, compared with the carrying amounts of $1,179.9 million and $524.1 million, respectively.

During the year ended December 31, 2012, the Partnership completed the Cardinal 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. Due to the recent date of the Cardinal Acquisition, the accounting for the business combination has not been completed. The estimates of fair value reflected as of December 31, 2012 are subject to change and changes could be material. Revision to these estimates will be recorded retrospectively.

NOTE 13 ACCRUED LIABILITIES

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

	December 31, 2012	December 31, 2011
Accrued capital expenditures	$ 8,336	$ 10,128
Cardinal Acquisition payable (offset by funds in escrow)	25,000	
Acquisition-based short-term contingent consideration	6,000	
Accrued ad valorem taxes	3,950	3,615
Other	14,466	9,539
	$ 57,752	$ 23,282

122

Table of Contents

NOTE 14 DEBT

Total debt consists of the following (in thousands):

	December 31, 2012	December 31, 2011
Revolving credit facility	$ 293,000	$ 142,000
8.75% Senior notes due 2018	370,184	370,983
6.625% Senior notes due 2020	505,231	
Capital lease obligations	11,503	11,157
Total debt	1,179,918	524,140
Less current maturities	(10,835)	(2,085)
Total long term debt	$ 1,169,083	$ 522,055

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

Years Ended December 31:	
2013	$ 10,835
2014	423
2015	240
2016	5
2017	293,000
Thereafter	865,822
Total principal maturities	1,170,325
Unamortized premium	9,593
Total debt	$ 1,179,918

Cash payments for interest related to debt, net of capitalized interest, were $28.3 million, $27.4 million and $88.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Revolving Credit Facility

At December 31, 2012, 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, 2012, was 2.6%. 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, 2012. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At December 31, 2012, the Partnership had $306.9 million of remaining committed capacity under its revolving credit facility.

In July 2011, the revolving credit facility was increased from $350.0 million to $450.0 million.

On May 31, 2012, the Partnership entered into an amendment to its revolving credit facility agreement, which among other changes:

increased the revolving credit facility from $450.0 million to $600.0 million;

extended the maturity date from December 22, 2015 to May 31, 2017;

reduced the Applicable Margin used to determine interest rates by 0.50%;

revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the credit agreement) or $340 million, provided the Partnership is in pro forma compliance with the financial covenants and has a Minimum Liquidity (as defined in the credit agreement) of at least $50 million; and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets ;

revised the definition of Consolidated EBITDA , which is used to calculate financial covenant compliance, to permit the Partnership to include estimated projected Consolidated EBITDA for the first 12 months following the commencement of commercial operations of a capital expansion project with a cost in excess of $20 million, net of actual Consolidated EBITDA attributable to such capital expansion project, provided, however, that the projected Consolidated EBITDA from any such projects, in the aggregate, may not be included to the extent such amounts exceed 15% of unadjusted Consolidated EBITDA; and

provided for the potential increase of revolving credit commitments up to an additional $200.0 million.

In December 2012, the Partnership entered into an amendment to its revolving credit facility agreement, which provided for (1) the Cardinal Acquisition (see Note 3) to be a permitted investment; and (2) Centrahoma to not be required to be a guarantor nor provide a security interest in its assets.

Borrowings under the revolving credit facility are secured by a lien on and security interest in all the Partnership s property and that of its subsidiaries, except for the assets owned by the WestOK, WestTX and Centrahoma joint ventures and their respective subsidiaries; and 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. As of December 31, 2012, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At December 31, 2012, the Partnership had $370.2 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $505.2 million principal outstanding of 6.625% Senior Notes (with the 8.75% Senior Notes, the Senior Notes).

The 8.75% Senior Notes are presented combined with a net $4.4 million unamortized premium as of December 31, 2012. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

The 6.625% Senior Notes are presented combined with a net $5.2 million unamortized premium as of December 31, 2012. 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.

In November 2010, the Partnership paid $1.3 million to the holders of the 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) in connection with a solicited consent received from the majority of holders of the 8.125% Senior Notes to amend certain provisions of the indenture governing the 8.125% Senior Notes. The amendment allowed the Partnership to make certain capital contributions to Laurel Mountain (see Note 4). The $1.3 million was recorded as deferred financing costs within other assets on the Partnership s consolidated balance sheets and was amortized over the remaining life of the 8.125% Senior Notes until the 8.125% Senior Notes were redeemed.

On April 7, 2011, the Partnership redeemed $7.2 million of the 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 April 8, 2011, the Partnership redeemed all the 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.

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 September 28, 2012, the Partnership issued $325.0 million of the 6.625% Senior Notes in a private placement transaction. The 6.625% Senior Notes were issued 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 $176.5 million after underwriting commissions and other transaction costs and utilized the proceeds to partially finance the Cardinal Acquisition (see Note 3).

In connection with the issuance of the 6.625% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013 in the case of the 6.625% Senior Notes issued in September, or by

Table of Contents

December 15, 2013, in the case of the 6.625% Senior Notes issued in December. If the Partnership does not meet the aforementioned deadline, the 6.625% Senior Notes issued on September 28, 2012 and December 20, 2012 will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated.

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, 2012.

Capital Leases

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.

During the year ended December 31, 2011, the Partnership amended an operating lease for eight natural gas compressors to require a mandatory purchase of the equipment at the end of the lease term, thereby converting the agreement to a capital lease upon the effective date of the amendment. As a result, the Partnership recorded an asset of $11.4 million 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 on the minimum payments required under the lease and the Partnership s incremental borrowing rate.

The following is a summary of the leased property under capital leases as of December 31, 2012 and 2011, which are included within property, plant and equipment (see Note 7) (in thousands):

	December 30, 2012	December 31, 2011
Pipelines, processing and compression facilities	$ 15,457	$ 12,507
Less accumulated depreciation	(1,066)	(199)
	$ 14,391	$ 12,308

Depreciation expense for leased properties was $723 thousand, $152 thousand and $47 thousand for the years ended December 31, 2012, 2011 and 2010, respectively, which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 7).

Table of Contents

As of December 31, 2012, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2013	$ 11,264
2014	435
2015	245
2016	6
2017	
Thereafter	
Total minimum lease payments	11,950
Less amounts representing interest	(447)
Present value of minimum lease payments	11,503
Less current portion of capital lease obligations	(10,835)
Long-term capital lease obligations	$ 668

NOTE 15 - 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, 2012, 2011 and 2010 was $5.5 million, $5.5 million and $6.4 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2012 is as follows (in thousands):

Years Ended December 31:	
2013	$ 3,935
2014	3,755
2015	3,692
2016	2,625
2017	701
Thereafter	1,600
	$ 16,308

The Partnership has certain long-term unconditional purchase obligations and commitments, primarily throughput contracts. These agreements provide transportation services to be used in the ordinary course of the Partnership s operations. Transportation fees paid related to these contracts were $10.5 million, $10.3 million and $9.5 million, respectively, for the years ended December 31, 2012, 2011, and 2010, respectively. The future fixed and determinable portion of the obligations as of December 31, 2012 was as follows: 2013 - $9.1 million; 2014 - $9.5 million; 2015 to 2017 - $3.5 million per year.

The Partnership had committed approximately $101.3 million for the purchase of property, plant and equipment at December 31, 2012.

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.

Table of Contents

NOTE 16 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 19). 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. For the year ended December 31, 2010, the Partnership had two customers that individually accounted for approximately 58% and 17%, respectively, of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. Additionally, the Partnership had two customers that individually accounted for approximately 45% and 14%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2012, and two customers that individually accounted for approximately 56% and 15%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2011.

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.

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, 2012, the Partnership and its subsidiaries had $4.1 million in deposits at banks, of which $3.7 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 17 BENEFIT PLANS

Generally, all 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, which 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 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 shall determine how the exercise price may be paid by the grantee. The Compensation Committee will determine 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, 2012, the Partnership had 1,053,242 phantom units outstanding under the Partnership s LTIPs, with 1,524,317 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

Partnership Phantom Units. Through December 31, 2012, 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, effective June 1, 2010, to exchange their Bonus Units for an equivalent number of phantom units. The first annual vesting for these units occurred on June 1, 2010. The remaining phantom units vest over a two 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, 2012, there were 291,359 units outstanding under the LTIPs that will vest within the following twelve months. 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. 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, 2012 include DERs granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $2.0 million, $0.8 million and $0.2 million during the years ended December 31, 2012, 2011 and 2010, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

Table of Contents

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

	Years Ended December 31,					
	2012		2011		2010	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	394,489	$ 21.63	490,886	$ 11.75	52,233	$ 39.72
Granted	907,637	34.94	178,318	33.47	575,112	10.49
Matured(2)(3)	(181,209)	17.88	(233,465)	11.34	(126,584)	17.11
Forfeited	(67,675)	29.83	(41,250)	13.49	(9,875)	17.39
Outstanding, end of period(4)(5)	1,053,242	$ 33.21	394,489	$ 21.63	490,886	$ 11.75
Non-cash compensation expense recognized (in thousands)(6)		$ 11,635		$ 3,271		$ 3,480

(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, 2012, 2011 and 2010 were $5.5 million and $7.4 million and $1.5 million, respectively.

(3) There were 792 and 414 matured phantom units, which were settled for $26 thousand and $14 thousand cash during the years ended December 31, 2012 and 2011, respectively. No phantom units were cash settled during the year ended December 31, 2010.

(4) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2012 and 2011 was $33.3 million and $14.7 million, respectively.

(5) There were 17,926 and 14,675 outstanding phantom unit awards at December 31, 2012 and 2011, 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. Non-cash compensation expense includes $2.2 million related to Bonus Units converted to phantom units during the year ended December 31, 2010.

At December 31, 2012, the Partnership had approximately $23.2 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 2.2 years.

Partnership Unit Options. At December 31, 2012, 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, 2012, all unit options had been exercised.

Table of Contents

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

	Years Ended December 31,					
	2012		2011		2010	
	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	100,000	$ 6.24
Granted						
Exercised[1]			(75,000)	6.24	(25,000)	6.24
Outstanding, end of period[2]		$		$	75,000	$ 6.24
Weighted average fair value of unit options per unit granted during the period		$		$		$
Non-cash compensation expense recognized (in thousands)[3]		$		$ 3		$ 4

(1) The intrinsic value for option unit awards exercised during the years ended December 31, 2011 and 2010 was $1.7 million and $0.5 million, respectively. Approximately $0.5 million and $0.2 million were received from exercise of unit option awards during the years ended December 31, 2011 and 2010, respectively.
(2) The aggregate intrinsic value of options outstanding at December 31, 2010 was $1.4 million.
(3) 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 allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants). The APLMC Plan is administered by a committee appointed by the CEO of the General Partner. Under the APLMC Plan, cash bonus units (Bonus Unit) may be awarded to Participants at the discretion of the committee. A Bonus Unit entitles 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 vest ratably over a three year period from the date of grant and will automatically vest 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 Bonus Units and 24,750 Bonus Units, respectively, vested and cash payments were made for $0.7 million and $0.9 million, respectively. The Partnership recognized compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized income of $79 thousand and $176 thousand during the years ended December 31, 2012 and 2010, respectively 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. The Partnership had $0.8 million at December 31, 2011 included within accrued liabilities on its consolidated balance sheets with regard to these awards, which represented their fair value as of that date. At December 31, 2012, Atlas Pipeline Mid-Continent LLC had no outstanding Bonus Units under the APLMC Plan and does not anticipate any further grants under the APLMC Plan.

NOTE 18 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. These costs and expenses are limited to $1.8 million for the twelve months following the closing of the Chevron Merger (see Note 4). The Partnership reimbursed the General Partner and its affiliates $3.8 million, $1.8 million and $1.5 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010. The General Partner believes that 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 $0.4 million, $0.3 million and $0.6 million in compression and gathering fees for the years ended December 31, 2012, 2011 and 2010, respectively.

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 June 2012, the Partnership acquired a gas gathering system and related assets in the Barnett Shale play in Tarrant County, Texas. The system consists of 19 miles of gathering pipeline that is used to facilitate gathering some of the newly-acquired production for ARP. By virtue of the acquisition, the Partnership became party to a management and operating services agreement (which had been negotiated and was in existence between unaffiliated third parties prior to the acquisition), whereby ARP operated the gathering system on the Partnership s behalf and was paid management and operating fees of approximately $39 thousand to cover ARP s cost of services. The agreement was terminated in the fourth quarter of 2012.

NOTE 19 SEGMENT INFORMATION

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

The Gathering and Processing segment consists of (1) the Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma 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 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). Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

Table of Contents

The Transportation and Treating segment consists of the contract 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.

In connection with the Cardinal Acquisition (see Note 3), the Partnership reviewed the acquired assets to determine the proper alignment of these assets with the existing reportable segments. The gas gathering and processing facilities acquired, along with their related assets, are included in the Gathering and Processing segment. The fixed fee contract gas treating business acquired in the Cardinal Acquisition generates revenue based upon monthly lease fees. The Partnership included these assets in the Pipeline Transportation segment and renamed it Transportation, Treating and Other .

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, 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		6,323		6,323
Income 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

	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	462	4,563		5,025
Gain on asset sale and other	256,272			256,272
Loss on early extinguishment of debt			(19,574)	(19,574)
Net 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
Year Ended December 31, 2010:				
Revenue:				
Revenues third party[1]	$ 956,483	$	$ (21,514)	$ 934,969
Revenues affiliates	619			619
Total revenues	957,102		(21,514)	935,588
Costs and expenses:				
Operating costs and expenses	769,946			769,946
General and administrative[1]			34,021	34,021
Depreciation and amortization	74,897			74,897
Interest expense[1]			87,273	87,273
Total costs and expenses	844,843		121,294	966,137
Equity income	4,920			4,920
Loss on asset sale and other	(10,729)			(10,729)
Loss on early extinguishment of debt			(4,359)	(4,359)
Net income (loss) from continuing operations	106,450		(147,167)	(40,717)
Income from discontinued operations			321,155	321,155
Net income (loss)	$ 106,450	$	$ 173,988	$ 280,438

	Years Ended December 31,		
	2012	2011	2010

Capital Expenditures:			
Gathering and Processing	$ 373,533	$ 245,426	$ 46,636
Transportation and Treating			
	$ 373,533	$ 245,426	$ 46,636

Table of Contents

	December 31, 2012	December 31, 2011
Balance Sheet		
Equity method investment in joint venture:		
Transportation and Treating	86,002	86,879
Goodwill:		
Gathering and Processing	292,448	
Transportation and Treating	26,837	
	$ 319,285	$
Total assets:		
Gathering and Processing	$ 2,831,639	$ 1,806,550
Transportation and Treating	141,356	87,053
Corporate and other	92,643	37,209
	$ 3,065,638	$ 1,930,812

(1) The Partnership notes 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) The Partnership notes that for the year ended December 31, 2012, acquisition costs related to the Cardinal Acquisition have not been allocated to its reportable segments, as it would be unfeasible to reasonably do so.

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

	Years Ended December 31, 2012	2011	2010
Natural gas and liquids sales:			
Natural gas	$ 396,867	$ 400,991	$ 299,461
NGLs	657,271	795,122	548,308
Condensate	85,234	72,037	41,933
Other	(2,111)	45	346
Total	$ 1,137,261	$ 1,268,195	$ 890,048

NOTE 20 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 as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 include the financial statements of 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. As of December 31, 2012, the Partnership s consolidated financial statements also include Centrahoma, in which the Partnership has a 60% interest. Under the terms of the Senior Notes and the revolving credit facility, WestOK LLC, WestTX LLC and Centrahoma 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, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010. 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):

135

Table of Contents

Balance Sheets

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
December 31, 2012					
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 asset		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
December 31, 2011					
Assets					
Cash and cash equivalents	$	$ 168	$	$	$ 168
Accounts receivable affiliates	302,837	43,148		(345,985)	
Other current assets	151	30,486	103,414	(1,353)	132,698
Total current assets	302,988	73,802	103,414	(347,338)	132,866
Property, plant and equipment, net		275,514	1,292,314		1,567,828
Intangible assets, net			103,276		103,276
Equity method investment in joint venture		86,879			86,879
Long term portion of derivative asset		14,814			14,814
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,427,152	2,035,533		(3,462,685)	
Other assets, net	20,750	1,773	2,626		25,149
Total assets	$ 1,750,890	$ 2,488,315	$ 3,354,558	$ (5,662,951)	$ 1,930,812

Liabilities and Equity					
Accounts payable affiliates	$	$	$ 348,660	$ (345,985)	$ 2,675
Other current liabilities	1,551	32,410	135,770		169,731
Total current liabilities	1,551	32,410	484,430	(345,985)	172,406
Long-term debt, less current portion	512,983		9,072		522,055
Other long-term liability	128	(5)			123
Equity	1,236,228	2,455,910	2,861,056	(5,316,966)	1,236,228
Total liabilities and equity	$ 1,750,890	$ 2,488,315	$ 3,354,558	$ (5,662,951)	$ 1,930,812

136

Table of Contents

Statements of Operations and Other Comprehensive Income

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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	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
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	341,355	139,480		(475,810)	5,025
Gain on asset sales and other		256,272			256,272
Loss on early extinguishment of debt	(19,574)				(19,574)
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

Table of Contents

Statements of Operations and Other Comprehensive Income

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2010					
Total revenues	$	$ 168,057	$ 767,531	$	$ 935,588
Total costs and expenses	(43,947)	(267,517)	(654,673)		(966,137)
Equity income	328,799	116,812		(440,691)	4,920
Loss on asset sales and other		(10,729)			(10,729)
Loss on early extinguishment of debt		(4,359)			(4,359)
Income (loss) from continuing operations	284,852	2,264	112,858	(440,691)	(40,717)
Income from discontinued operations		321,155			321,155
Net income (loss)	$ 284,852	$ 323,419	$ 112,858	$ (440,691)	$ 280,438
Income attributable to non-controlling interest			(4,738)		(4,738)
Preferred unit dividends	(780)				(780)
Net income (loss) attributable to common limited partners and the General Partner	284,072	323,419	108,120	(440,691)	274,920
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	37,966	37,966		(37,966)	37,966
Comprehensive income (loss)	$ 322,038	$ 361,385	$ 108,120	$ (478,657)	$ 312,886

138

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
Year Ended December 31, 2010					
Net cash provided by (used in):					
Continuing operating activities	$ 386,703	$ 36,633	$ 178,148	$ (518,431)	$ 83,053
Discontinued operating activities		23,374			23,374
Total operating activities	386,703	60,007	178,148	(518,431)	106,427
Continuing investing activities	315,193	835,745	(38,336)	(1,187,041)	(74,439)
Discontinued investing activities		669,192			669,192
Total investing activities	315,193	1,504,937	(38,336)	(1,187,041)	594,753
Total financing activities	(701,896)	(1,565,801)	(139,812)	1,705,472	(702,037)
Net change in cash and cash equivalents		(857)			(857)
Cash and cash equivalents, beginning of period		1,021			1,021
Cash and cash equivalents, end of period	$	$ 164	$	$	$ 164

Table of Contents

NOTE 21 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, 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 (benefit)	(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.

	Fourth Quarter[(1)]	Third Quarter[(2)]	Second Quarter[(3)]	First Quarter[(4)]
	(in thousands, except per unit data)			
Year ended December 31, 2011:				
Revenue	$ 315,906	$ 379,780	$ 350,185	$ 256,863
Costs and expenses	(323,849)	(331,307)	(322,206)	(271,617)
Equity income in joint ventures	2,091	1,785	687	462
Gain (loss) on sale of asset	598		(273)	255,947
Loss on early extinguishment of debt			(19,574)	
Income (loss) from continuing operations	(5,254)	50,258	8,819	241,655
Loss from discontinued operations				(81)
Net income (loss)	(5,254)	50,258	8,819	241,574
Income attributable to non-controlling interests	(1,708)	(1,760)	(1,545)	(1,187)
Preferred unit dividends			(149)	(240)
Net income (loss) attributable to common limited partners and the General Partner	$ (6,962)	$ 48,498	$ 7,125	$ 240,147
Net income (loss) attributable to common limited partners per unit basic and diluted[(5)]	$ (0.15)	$ 0.87	$ 0.13	$ 4.37

(1) Net income includes a $27.0 million non-cash derivative loss.
(2) Net income includes a $27.0 million non-cash derivative gain.
(3) Net income includes a $13.8 million non-cash derivative gain and a $0.3 million loss on sale of Laurel Mountain (see Note 4).
(4) Net income includes an $18.4 million non-cash derivative loss and a $255.9 million gain on sale of Laurel Mountain (see Note 4).
(5) For the fourth quarter of the year ended December 31, 2011, approximately 391,000 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.

NOTE 22 SUBSEQUENT EVENTS

On January 7, 2013, the Partnership paid $6.0 million for the first of two Trigger Payments related to the acquisition of a gas gathering system and related assets in February 2012. The Partnership 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 within certain specified time periods. Sufficient volumes were achieved in December 2012 to meet the required minimum volumes for the first Trigger Payment (see Note 12).

On January 23, 2013, the Partnership declared a cash distribution of $0.58 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2012. The $40.6 million distribution, including $3.1 million to the General Partner for its general partner interest and incentive distribution rights, was paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013 (see Note 6).

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, (representing approximately 73.4% of the outstanding 8.75% Senior Notes) were validly tendered as of the expiration date of the consent solicitation. On February 11, 2013, the Partnership 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. The Partnership also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer. The Partnership plans to fund the redemption with a portion of the net proceeds from the issuance of the 5.875% unsecured Senior Notes due 2023 (5.875% Senior Notes).

On February 11, 2013, the Partnership issued $650.0 million of 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of $637.8 million and plans to utilize the proceeds to redeem any or all of its outstanding 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the revolving credit facility. The Partnership has agreed to file a registration statement with respect to the 5.875% Senior Notes.

Table of Contents

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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, excluding the assets acquired through the Cardinal Acquisition, which was completed on December 20, 2012 (see Item 8. Financial Statements and Supplementary Data Note 3). Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2012, 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 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.

In conducting management s evaluation of the effectiveness of its internal control over financial reporting, management has excluded, due to the timing, size, and complexity, the operations of newly acquired assets from the Cardinal Acquisition from its December 31, 2012 Sarbanes-Oxley 404 review (see Item 8. Financial Statements and Supplementary Data Note 3). In connection with the Cardinal Acquisition, we have entered into transition services agreements with the previous owners and, as a result, we will not begin to perform substantially all accounting control functions until March 20, 2013. The assets acquired with the Cardinal Acquisition constituted 24.3% of our total assets and 0.7% of our total revenues for the year ended December 31, 2012. We are continuing to integrate these systems historical internal controls over financial reporting with our existing internal controls over financial reporting. This integration may lead to changes in our or the acquired systems historical internal controls over financial reporting in future fiscal reporting periods.

Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2012. 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, 2012, which is included herein.

Other than Cardinal Acquisition, there have been no changes in our internal control over financial reporting during the fourth quarter of 2012 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, 2012, based on criteria established in *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 (Management s Report). Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit. Our audit of, and opinion on, the Partnership s internal control over financial reporting does not include the internal control over financial reporting of Cardinal Midstream, LLC (renamed APL Arkoma, LLC), a wholly-owned subsidiary, whose financial statements reflect total assets and revenues constituting 20 and one percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012. As indicated in Management s Report, APL Arkoma, LLC was acquired during 2012, and therefore, management s assertion on the effectiveness of the Partnership s internal control over financial reporting excluded internal control over financial reporting of APL Arkoma, LLC.

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.

Table of Contents

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *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, 2012, and our report dated February 28, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 28, 2013

Table of Contents

ITEM 9B. OTHER INFORMATION

None.

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 will rotate 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 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	74	Executive Chairman of the Managing Board	1999
Jonathan Z. Cohen	42	Executive Vice Chairman of the Managing Board	1999
Eugene N. Dubay	64	Chief Executive Officer, President and Managing Board Member	2008
Robert W. Karlovich, III	35	Chief Financial Officer	2009
Patrick J. McDonie	52	Senior Vice President and Chief Operating Officer	2012
Gerald R. Shrader	53	Chief Legal Officer and Secretary	2009
Tony C. Banks	58	Managing Board Member	1999
Curtis D. Clifford	70	Managing Board Member	2004
Gayle P. W. Jackson	66	Managing Board Member	2011
Martin Rudolph	66	Managing Board Member	2005
Michael L. Staines	63	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. 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 that he has accumulated through his activities as a financier and investor, add 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 President and Chief Executive Officer of our General Partner since January 2009. 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.

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

Table of Contents

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.

Patrick J. McDonie has been Senior Vice President and Chief Operating Officer of our General Partner since July 2012. 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.

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 8 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.

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 contributing his services and expertise for selected clients.

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 46 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 and products and responsibilities for 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 s 40 years of experience as an independent certified public accountant 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 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.

Table of Contents

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 members believe 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 position. The managing board members believe 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

Effective as of April 25, 2012, the duties of our former risk oversight committee were assumed by our audit committee. 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 of our General Partner during regular board meetings.

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.

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 2012.

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. These costs and expenses were limited to $1.8 million for the twelve months following the Laurel Mountain Sale on February 17, 2011, excluding compensation, benefits and expenses of officers and employees whose primary responsibility is our management and operation. 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 2012 we reimbursed our General Partner and its affiliates $3.8 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. Effective as of April 25, 2012, the members of the audit committee became Messrs. Rudolph and Banks and Dr. Jackson, with Mr. Rudolph acting as the chairman. Prior to that time, Mr. Clifford also served on the audit committee. 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.

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 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. 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.

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

Table of Contents

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, 2012, 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.

We do not directly compensate our NEOs. ATLS allocates the compensation of our executive officers 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. Because Messrs. Dubay, Karlovich and McDonie devoted all their time to us, all their compensation costs were allocated to us. Until April 2012, the ATLS compensation committee, comprised solely of independent directors, was responsible for (i) formulating and presenting recommendations to its board of directors with respect to the compensation of our CEO, CFO and our NEOs; and (ii) administering our employee benefit plans (including our incentive plans and programs). Since that time, our compensation committee has assumed responsibility for designing our compensation objectives and methodology and determining compensation payable to those officers and employees (including some of our NEOs) who devote all of their time to our business. Our compensation committee also administers our benefit plans and programs. The ATLS compensation committee continues to determine compensation for officers and employees (including some of our NEOs) who do not devote all of their time to us. ATLS administers its own benefit plans, some costs of which may be 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.

Compensation Methodology

Our compensation committee generally establishes or, acting in its discretion, makes recommendations to our managing board regarding, compensation amounts shortly after the close of our fiscal year. In the case of base salaries, it approves, or recommends, the amounts to be paid for the new fiscal year. In the case of annual cash 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 pay annual cash awards in February, although the compensation committee has the discretion to recommend salary adjustments, as well as cash incentives and issue 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 the 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 the 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 the 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.

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 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.

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 on 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 management level employees in our organization, because the peer group analysis did not generate adequate compensation information other than for our top four executives.

Following the establishment of the peer group, Meridian then performed an analysis to assess our 2012 executive compensation program against the peer group with respect to our (i) executive base salaries; (ii) executive target bonus compensation; and (iii) 2012 equity awards. 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. Meridian also advised our compensation committee with respect to compensation practices generally.

Our compensation committee also asked Meridian to assess a review of the annual compensation paid to our outside directors. In February 2013, following its review of recommendations made by Meridian and our compensation committee, the ATLS nominating and governance committee approved 2013 annual compensation for our non-employee directors comprised of cash and equity. See Directors Compensation.

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.

Table of Contents

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 cash incentives 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 Cash Incentives

Annual cash incentives are intended to tie a significant portion of each of our NEOs 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 cash compensation is generally discretionary in nature.

Performance-Based Bonuses. In April 2011, the ATLS compensation committee adopted an Annual Incentive Plan for Senior Executives, which we refer to as the ATLS Senior Executive Plan, to award bonuses for achievement of predetermined performance objectives during a 12-month performance period, generally coinciding with ATLS fiscal year. Awards under the ATLS Senior Executive Plan may be paid in cash or in a combination of cash and equity. Under the ATLS Senior Executive Plan, the maximum award payable to an individual is $15,000,000.

During 2012, the ATLS compensation committee approved 2012 target bonus awards to be paid from a bonus pool. The bonus pool is equal to 18.3% of ATLS distributable cash flow. In the event that distributable cash flow included any capital transaction gains in excess of $50 million, then only 10% of that excess would be included in the bonus pool. If ATLS distributable cash flow did not equal at least 80% of average distributable cash flow for the past three years, no bonuses would be paid in the absence of special circumstances. Distributable cash flow means the sum of (i) cash available for distribution by ATLS, including its ownership interest in the distributable cash flow of any of its subsidiaries (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 capital investment in a subsidiary was not intended to be included and, accordingly, if ATLS 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 basis in the subsidiary.

The maximum award payable, expressed as a percentage of ATLS estimated 2012 distributable cash flow, for certain of our NEOs was as follows: Mr. E. Cohen, 6.5% and Mr. J. Cohen, 6.2%. Messrs. Dubay, McDonie and Karlovich did not participate in the ATLS Senior Executive Plan. Pursuant to the terms of the ATLS Senior Executive Plan, the ATLS compensation committee had the discretion to recommend reductions, but not increases, in awards under the Plan. A portion of the cash amount awarded to our participating NEOs is allocated to us.

Table of Contents

Discretionary Bonuses. Generally, annual cash incentive compensation paid by us is discretionary in nature, based on individual and group performance. 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.

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 cash incentives with our financial performance and the resulting benefits to our unitholders, as well as recognizing 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. Our NEOs are also eligible to receive awards under the ATLS long-term incentive plans, which we refer to as the ATLS Plans.

Grants under 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.

Grants under Other Plans: In addition, our NEOs may be eligible to receive stock-based awards under the ATLS Plans and under the long-term incentive plan adopted by Atlas Resource Partners, L.P., an ATLS subsidiary (NYSE: ARP) (ARP).

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.

Table of Contents

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 2012, these benefits were limited to providing cars to some NEOs and reimbursement of club membership dues.

Determination of 2012 Compensation Amounts

Base Salary

In February 2012, the ATLS compensation committee approved the base salaries for our NEOs as follows: Mr. Dubay - $500,000 and Mr. Karlovich - $286,000. These amounts represented a 0% and 11.5% increase from the 2011 base salaries for each of Messrs. Dubay and Karlovich, respectively. In connection with his retention in July 2012, our compensation committee established Mr. McDonie s initial base salary at $350,000.

In February 2013, our compensation committee approved the base salaries for our NEOs as follows: Mr. Dubay - $500,000, Mr. Karlovich - $310,000 and Mr. McDonie - $375,000. These amounts represent a 0%, 8.4% and 7.1% increase from the 2012 year-end base salaries for Messrs. Dubay, Karlovich and McDonie, respectively. In determining base salaries for 2013, our compensation committee recognized that the proposed base salaries generally align with the 75th percentile of peer group data provided by Meridian. Mr. Dubay s 2013 base salary was approximately $7,500 less than 75th percentile of the Meridian peer group data, Mr. McDonie s 2013 base salary is approximately $15,000 more than the 75th percentile of the Meridian peer group data, and Mr. Karlovich s 2013 base salary is approximately $10,000 more than the 75th percentile of the Meridian peer group data.

Annual Cash and Long-Term Incentives

Performance-Based Bonuses. After the end of ATLS 2012 fiscal year, its compensation committee considered incentive awards pursuant to the ATLS Senior Executive Plan based on the prior year s performance. In determining the actual amounts to be paid to certain of our NEOs, the ATLS compensation committee considered both individual and company performance. ATLS CEO made recommendations of incentive award amounts based upon its performance as well as the performance of its subsidiaries; however, the compensation committee had the discretion to approve, reject, or modify the recommendations. The ATLS compensation committee granted awards to our participating NEOs at the maximum level, partially in the form of ATLS equity awards. The amount of the cash awards allocated to us was as follows: Mr. E. Cohen - $302,500 and Mr. J. Cohen - $351,000.

Discretionary Bonuses. Mr. McDonie s target bonus is established by his employment agreement and Mr. Dubay s and Mr. Karlovich s target bonuses were established based on the recommendation of management and with reference to the peer group data provided to us. For these individuals, target bonus amounts, as a percentage of base salary, were established as follows:

Name	**2012 Target Bonus**
Eugene N. Dubay	100%
Patrick J. McDonie	100%(1)
Robert W. Karlovich, III	65%

(1) Mr. McDonie s target bonus is generally 100% of base salary (prorated), but is guaranteed for 2012 at a minimum of $200,000.

In negotiating Mr. McDonie s employment agreement, we agreed to pay a target bonus he was then receiving from his previous employer. For 2012, Mr. McDonie is entitled to minimum discretionary annual bonus of $200,000, an amount roughly equivalent to his target bonus pro-rated as of the date he started employment with us.

In determining cash incentive awards for 2012, our compensation committee considered financial and operational performance beginning in January 2009, as well as the contributions of our management group over the preceding four-year period (2009-2012), taken as a whole. In particular, our compensation committee noted the diligent and sustained efforts of our management team to steadily improve our financial and operating performance throughout the period. At the request of our compensation committee, management presented the following metrics with regard to this improvement: (i) an increase in the unit price from $3 per unit in 2009 to approximately $32 per unit by December 31, 2012; (ii) an increase in our market capitalization from approximately $150 million in 2009 to in excess of $2 billion by the end of 2012; and (iii) an increase in distributions from $0 per unit in 2009 to $2.27 per unit in 2012. Our compensation committee then noted the strong performance of our executive group during 2012, outlining the following achievements: (i) completion of expansions to the Velma and Waynoka processing facilities; (ii) substantial completion of construction of the new Driver processing plant, without recording any lost time injuries; (iii) closing on numerous equity and bond offerings, substantially increasing our liquidity and decreasing the interest rate payable under our outstanding unsecured debt; and (iv) closing on the Cardinal Acquisition in a timely, accelerated manner prior to year-end 2012**.**

Based on these considerations, our committee awarded discretionary bonuses to Mr. Dubay, Mr. McDonie and Mr. Karlovich of $1,500,000, $600,000 and $585,000, respectively. Based on the extraordinary performance of the management team, the compensation committee determined it was appropriate to consider performance over a multiple year period and, based on this analysis, granted the one-time awards noted above, which are substantially in excess of target bonuses. In addition, our compensation committee awarded discretionary bonuses in the amount of $1,000,000 to each of Mr. E. Cohen and Mr. J. Cohen. In light of bonuses paid to our NEOs who devote all of their time to us, our compensation committee also determined it was appropriate to make these awards to Messrs. E. Cohen and J. Cohen for providing the necessary strategic direction and insight with respect to our financing activities and growth opportunities.

Long-Term Incentives. In April, 2012, the compensation committee made the following awards of phantom units to our NEOs: (1) Mr. E. Cohen 100,000 phantom units; (2) Mr. J. Cohen 100,000 phantom units; (3) Mr. Dubay 100,000 phantom units; and (4) Mr. Karlovich 20,000 phantom units. The awards will vest 25% on each anniversary of the grant. Prior to the awards being made, Messrs. E. Cohen, J. Cohen and E. Dubay, held no outstanding equity awards in us. As such, our compensation committee determined it was appropriate to award the phantom units in order to insure continued dedication to our business.

In connection with his employment agreement, in 2012 Mr. McDonie was awarded 70,000 phantom units in us and 20,000 phantom units in ATLS. The phantom units in us vest 25% on each anniversary of the date of the grant. The phantom units in ATLS vest 25% on the third anniversary and

Table of Contents

75% on the fourth anniversary of the award. The awards roughly equate to the equity awards forfeited by Mr. McDonie when he left his previous employer and, as such, were an essential component in retaining his services. The phantom unit awards in ATLS granted to Mr. McDonie served as an additional incentive to promote our interests, as well the interests of our general partner. Award of the units in us and ATLS, incentivizes our management team, including Mr. McDonie, to promote the continuing growth in our distributions, which not only benefits our General Partner, but also benefits our unitholders.

The long-term incentive awards granted to our NEOs were made prior to our compensation committee s retention of Meridian. Nonetheless, in reviewing our compensation program, Meridian observed that 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. Based on Meridian s report and observations, our compensation committee is evaluating the appropriate level of annual long-term incentive awards to be granted to our NEOs in the future.

The following tables set forth the compensation allocation to us for fiscal years 2012, 2011 and 2010 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. The Summary Compensation Table discloses only compensation, which is allocated to us.

Table of Contents

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Stock Awards[1]	Option Awards[2]	Non-Equity Incentive Plan Compensation[3]	All Other Compensation	Total
Eugene N. Dubay, CEO and President	2012	$ 500,000	$ 1,500,000	$ 3,498,000	$	$	$ 440,792[4]	$ 5,938,792
	2011	500,000		1,778,400	993,000	1,000,000	5,136,128	9,407,528
	2010	500,000	1,000,000	1,334,009	1,008,700		26,484	3,869,193
Robert W. Karlovich, III, CFO	2012	286,000	585,000	699,600			163,996[5]	1,734,596
	2011	220,192	350,000	1,628,300	99,300		69,188	2,366,980
	2010	179,358	63,000	304,200			9,538	556,096
Edward E. Cohen, Executive Chairman of the Board[6]	2012	98,577	1,000,000	3,498,000		302,500	206,097[7]	5,105,174
	2011	101,423				525,000	25,650	652,073
	2010	150,000				750,000	3,375	903,375
Jonathan Z. Cohen, Executive Vice Chairman of Atlas Pipeline GP[6]	2012	82,000	1,000,000	3,498,000		351,000	198,930[8]	5,129,930
	2011	72,115				450,000	21,375	543,490
	2010	105,000				600,000	1,688	706,688
Patrick J. McDonie, Senior Vice President and COO[9]	2012	156,154	600,000	2,997,000			93,617[10]	3,846,771
	2011							
	2010							

(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 12 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 our Plans and the ATLS Plans. See Item 8. Financial Statements and Supplementary Data Note 12 for further discussion regarding assumptions made in valuation of fair value.

(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 $86,199 with respect to the phantom units awarded under the ATLS Plans and $169,000 with respect to the phantom units awarded under our Plans. Also includes $185,484 representing monthly severance paid by Chevron in connection with the termination of Mr. Dubay s employment agreement for the remainder of the employment term as a result of the Chevron Merger.

(5) Includes payments on DERs of $10,775 with respect to the phantom units awarded under the ATLS Plans and $146,948 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 (i) payments on DERs of $169,000 with respect to the phantom units awarded under our Plans; (ii) $36,966 representing our allocated portion of a matching contribution under the Excess 401 (k) Plan; and (iii) our allocated portion of tax, title and insurance premiums for Mr. E. Cohen s automobile.

(8) Includes (i) payments on DERs of $169,000 with respect to the phantom units awarded under our Plans and (ii) $29,930 representing our allocated portion of a matching contribution under the Excess 401 (k) Plan.

(9) On July 3, 2012, Patrick J. McDonie was hired as Chief Operating Officer of our General Partner.

(10) Includes payments on DERs of $10,400 with respect to the phantom units awarded under the ATLS Plans and $79,100 with respect to the phantom units awarded under our Plans.

Table of Contents

GRANTS OF PLAN-BASED AWARDS

Name	Estimated Possible Payments Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Under-lying Options	Exercise or Base Price of Option Awards ($/Sh)(2)	Grant Date Fair Value of Unit and Option Awards(3)
Eugene N. Dubay	N/A	N/A	N/A	04/26/12	100,000(4)		$	$ 3,498,000
Robert W. Karlovich, III	N/A	N/A	N/A	04/26/12	20,000(4)			699,600
Edward E. Cohen	N/A	N/A	4,550,000	04/26/12	100,000(4)			3,498,000
				05/15/12	150,000(5)	350,000(6)	24.67	5,835,500
Jonathan Z. Cohen	N/A	N/A	4,300,000	04/26/12	100,000(4)			3,498,000
				05/15/12	150,000(5)	350,000(6)	24.67	5,835,500
Patrick J. McDonie	N/A	N/A	N/A	07/20/12	70,000(4)			2,352,000
				07/20/12	20,000(7)			645,000

(1) Represents performance-based bonuses under ATLS Senior Executive Plan. As discussed under Compensation Discussion and Analysis Elements of our Compensation Program Annual Incentives Performance-Based Bonuses, the ATLS compensation committee set performance goals based on ATLS distributable cash flow and established maximum awards, but not minimum or target amounts, for each eligible NEO. ATLS Senior Executive Plan sets an individual limit of $15,000,000 per annum regardless of the maximum amounts that might otherwise be payable.
(2) The exercise price is equal to the closing price of ATLS common units on the date of grant.
(3) The grant date fair value was calculated in accordance with FASB ASC Topic 718.
(4) Represents phantom units granted under our 2010 Plan.
(5) Represents phantom units granted under the ATLS 2012 Plan. Phantom units granted to Mr. E. Cohen and Mr. J. Cohen under the ATLS Plans are not allocated to us and are not included in the Summary Compensation Table.
(6) Represents options granted under the ATLS 2012 Plan. The weighted average fair value of unit options granted during the period, based upon a Black-Scholes option pricing model on the date of grant, was $6.10. Phantom units granted to Mr. E. Cohen and Mr. J. 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 2010 Plan.

Employment Agreements and Potential Payments Upon Termination or Change of Control

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 we cease to be a public company unless we become a subsidiary of a public company and,
  - in the case of Mr. E. Cohen, becomes the chief executive officer of the public parent immediately following the applicable transaction;

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

Table of Contents

in the case of Mr. Dubay, the CEO or the Chairman of our General Partner s board is not our CEO or the CEO of the acquiring entity;

the executive is required to relocate to a location more than 35 miles from the executive s previous location, and 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 our 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 our company and has continued for 30 days after written notice signed by a majority of the independent directors of our 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 the company or its 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

On May 13, 2011, ATLS entered into an employment agreement with Mr. Cohen to secure his service as President and Chief Executive Officer. As discussed above under Compensation Discussion and Analysis, ATLS allocated a portion of Mr. Cohen s compensation cost to us based on an estimate of

Table of Contents

the time spent by Mr. Cohen on our activities. ATLS added 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The agreement has an effective date of May 16, 2011 and 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.

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. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which ATLS must match on a dollar-for-dollar basis up to 50% of his annual base salary. 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 years of his average compensation (which is generally defined as the sum of (1) his base salary in effect immediately before the termination of employment plus (2) the average of the cash bonuses earned for the three calendar years preceding the year in which the date of termination of employment occurs, (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.

Table of Contents

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 three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year 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, 2012.

Reason for Termination	Lump Sum Severance Payment	Benefits(1)	Accelerated Vesting of Equity Awards(2)
Death	$ 412,500	$	$ 3,157,000
Disability	412,500	5,774	3,157,000
Termination by us without cause or by Mr. Cohen for good reason	1,897,500(3)	5,774	3,157,000

(1) Dental and medical benefits were calculated using 2012 COBRA rates.
(2) Represents the value of unvested unit awards granted under our 2010 plan 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.
(3) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Jonathan Z. Cohen

On May 13, 2011, ATLS entered into an employment agreement with Mr. Cohen to secure his service as Chairman of the Board. The agreement has an effective date of May 16, 2011 and 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. ATLS adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that were allocated in part to us.

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. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which ATLS must match on a dollar-for-dollar basis up to 50% of his annual base salary. 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.

Table of Contents

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 three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year 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, 2012.

Reason for Termination	Lump Sum Severance Payment	Benefits[1]	Accelerated Vesting of Equity Awards[2]
Death	$ 481,000	$	$ 3,157,000
Disability	481,000	10,623	3,157,000
Termination by us without cause or by Mr. Cohen for good reason	1,924,000[3]	10,623	3,157,000

(1) Dental and medical benefits were calculated using 2012 COBRA rates.
(2) Represents the value of unvested unit awards granted under our 2010 plan 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.
(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 effective date of November 4, 2011 and 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.

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 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 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.

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 lump sum termination amounts paid to Mr. Dubay would be allocated to us consistent with past practice. 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, 2012.

Table of Contents

Reason for Termination	Lump Sum Severance Payment	Benefits(1)	Accelerated Vesting of Equity Awards(2)
Death or Disability	$ 1,000,000	$	$ 7,735,136
Termination by us without cause or by Mr. Dubay for good reason	2,750,000(3)	16,822	7,735,136

(1) Dental and medical benefits were calculated using 2012 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, 2012. 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.

(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

In July 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 a one-time award of 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. For purposes of calculating the monthly severance payment upon termination of employment by ATLS without cause or by Mr. McDonie for good reason on or before December 31, 2012, the annual cash bonus paid to Mr. McDonie for the prior fiscal year is assumed to be $200,000. 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.

Table of Contents

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 year (assumed to be $200,000 if Mr. McDonie s employment is terminated due to death or disability on or before December 31, 2012); 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 lump sum termination amounts paid to Mr. McDonie would be allocated to us consistent with past practice. 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, 2012.

Reason for Termination	Lump Sum Severance Payment	Accelerated Vesting of Equity Awards(1)
Death or Disability	$ 950,000	$ 2,904,700
Termination by us without cause or by Mr. McDonie for good reason	3,000,000(2)	2,904,700

(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, 2012, 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 $2,269,709.

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.

Table of Contents

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 manager 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 managers 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 managers 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;

Table of Contents

- 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.

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

Table of Contents

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	03/25/2021	87,012(3)	$ 3,022,797
					100,000(4)	3,157,000
Robert W. Karlovich, III		10,876(5)	20.44	03/25/2021	10,876(6)	377,832
					50,000(7)	1,578,500
Edward E. Cohen	543,825(8)		20.75	11/10/2016		
		761,355(9)	20.44	03/25/2021	476,295(10)	16,546,488
		350,000(11)	24.67	05/15/2022	100,000(4)	3,157,000
Jonathan Z. Cohen	217,530(6)		20.75	11/10/2016		
		543,825(12)	20.44	03/25/2021	421,912(13)	14,657,223
		350,000(11)	24.67	05/15/2022	100,000(4)	3,157,000
Patrick J. McDonie			N/A	N/A	20,000(14)	694,800
					70,000(15)	2,909,900

(1) Based on closing market price of our common units on December 31, 2012 of $31.57 and price of ATLS common units on December 31, 2012 of $34.74.

(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: 04/26/13 25,000; 04/26/14 25,000; 04/26/15 25,000; and 04/26/16 25,000.

(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.

(7) Represents our phantom units, which vest as follows: 04/26/13 5,000; 11/04/13 10,000; 04/26/14 5,000; 11/04/14 10,000; 04/26/15 5,000; 11/04/15 10,000; and 04/26/16 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: 05/15/13 37,500; 03/25/14 81,573; 05/15/14 37,500; 03/25/15 244,722; 05/15/15 37,500; and 05/15/16 37,500.

(11) Represents options to purchase ARP units, which vest as follows: 05/15/13 87,500; 05/15/14 87,500; 05/15/15 87,500; and 05/15/16 87,500.

(12) Represents options to purchase ATLS units, which vest as follows: 03/25/14 135,956; 03/25/15 407,869.

(13) Represents ATLS phantom units, which vest as follows: 05/15/13 37,500; 03/25/14 67,978; 05/15/14 37,500; 03/25/15 203,934; 05/15/15 37,500; and 05/15/16 37,500.

(14) Represents ATLS phantom units, which vest as follows: 07/20/15 5,000; and 07/20/16 15,000.

(15) Represents our phantom units, which vest as follows: 07/20/13 17,500; 07/20/14 17,500; 07/20/15 17,500.

Table of Contents

2012 OPTION EXERCISES AND STOCK VESTED TABLE

	Option Awards		Unit Awards		
Name	Number of Units Acquired on Exercise	Value Realized on Exercise ($)	Number of Units Acquired on Vesting	Value Realized on Vesting ($)(1)	Total Value ($)
Eugene N. Dubay	51,988(2)	$ 1,527,393			$ 1,527,393
Robert W. Karlovich, III			21,250(3)	631,910	631,910
Edward E. Cohen					
Jonathan Z. Cohen					
Patrick J. McDonie					

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

Director Compensation

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash	Stock Awards	All Other Compensation(1)	Total
Tony C. Banks	$ 50,000	$ 49,985(2)	$ 8,927	$ 108,912
Curtis D. Clifford	50,000	49,975(3)	8,018	107,993
Gayle P.W. Jackson	50,000	63,225(4)	5,956	119,181
Martin Rudolph	65,000	49,980(5)	8,185	123,165
Michael Staines	50,000	49,982(6)	6,266	106,248

(1) Represents payments on DERs for phantom units.
(2) Represents 1,397 phantom units having a grant date fair value of $35.78 granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 2/11/13 349; 02/11/14 349; 2/11/15 349 and 2/11/16 350.
(3) Represents 1,503 phantom units having a grant date fair value of $33.25 granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 5/10/13 375; 5/10/14 375; 5/10/15 375 and 5/10/16 378.
(4) Represents 1,386 phantom units having a grant date fair value of $36.06 and 449 phantom units having a grant date fair value of $29.50, granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 02/18/13 346; 06/27/13 112; 02/18/14-346; 06/27/14 112; 02/18/15 346; 06/27/15 112; 02/18/16 348 and 06/27/16 113.
(5) Represents 1,349 phantom units having a grant date fair value of $37.05 granted under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 3/17/13 337; 3/17/14 337; 3/17/15 337 and 3/17/16 338.
(6) Represents 1,603 phantom units having a grant date fair value of $31.18 under our 2010 LTIP. The phantom units vest 25% on each anniversary of the date of grant as follows: 7/01/13 400; 7/01/14 400; 7/01/15 400 and 7/01/16 403.

Our General Partner did not pay additional remuneration to officers or employees of ATLS who also served as managing board members. In fiscal year 2012, each non-employee managing board member received an annual retainer of $50,000 in cash and an annual grant of phantom units with DERs; issued under our 2010 LTIP having a market value of approximately $50,000. In addition, the chairperson of the audit committee received payment in the amount of $15,000 in cash from our General Partner.

In February 2013, based on the recommendations presented by Meridian and our compensation committee, the ATLS nominating and governance committee approved, effective as of January 1, 2013, annual retainers for non-employee directors 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

Table of Contents

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. Based on the report provided by Meridian, the average annual compensation provided to our non-employee directors falls in the approximate range of 60-65% of average annual compensation of the relevant peer group developed by Meridian.

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.

Table of Contents

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, 2012.

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

Table of Contents

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 25, 2013 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.

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	130,300 (1)	*
Edward E. Cohen	114,100 (2)	*
Jonathan Z. Cohen	78,527 (3)	*
Patrick J. McDonie		*
Robert W. Karlovich, III	35,342 (4)	*
Tony C. Banks	4,323	*
Curtis D. Clifford	2,958	*
Gayle P. W. Jackson	3,370 (5)	*
Martin Rudolph	5,494 (6)	*
Michael L. Staines	12,176	*
Executive officers and Managing Board Members as a group (11 persons)	444,886	*
Other Owners of More than 5% of Outstanding Units		
Atlas Energy, L.P.	5,754,253 (7)	8.9%
Leon G. Cooperman	4,527,184 (8)	7.0%
FMR LLC.	3,664,314 (9)	5.7%

* Less than 1%.

(1) Includes (i) 25,000 phantom units granted pursuant to our 2010 Plan, which will vest into common units within 60 days, (ii) 47,125 units held in trust for the benefit of Mr. Dubay, (iii) 37,175 units held in trust for the benefit of Mr. Dubay s spouse, and (iv) 20,000 units held in trust for the benefit of Mr. Dubay s children.

(2) Includes (i) 25,000 phantom units granted pursuant to our 2010 Plan, which will vest into common units within 60 days, and (ii) 60,100 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 (i) 25,000 phantom units granted pursuant to our 2010 Plan, which will vest into common units within 60 days, and (ii) 48,650 units held jointly with Mr. J. Cohen s spouse.

(4) Includes (i) 5,000 phantom units granted pursuant to our 2010 Plan, which will vest into common units within 60 days, and (ii) 250 units held in trust for the benefit of Mr. Karlovich s children.

(5) Includes 2,170 units held in trust for the benefit of Dr. Jackson.

(6) Includes 1,052 phantom units granted pursuant to our 2004 and 2010 Plans, which will vest into common units within 60 days.

(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 8, 2013. The address for Mr. Cooperman is 2700 No. Military Trail, Suite 230, Boca Raton, FL 33431.

(9)

This information is based upon a Schedule 13G/A, which was filed with the SEC on February 14, 2013. The address for FMR LLC is 82 Devonshire Street, Boston, MA 02109.

Table of Contents

Equity Compensation Plan Information

The following table contains information about our 2004 LTIP as of December 31, 2012:

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	63,725	n/a	
Equity compensation plans approved by security holders Total	63,725		4,359

The following table contains information about our 2010 LTIP as of December 31, 2012:

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	989,517	n/a	
Equity compensation plans approved by security holders Total	989,517		1,519,958

The following table contains information about the ATLS 2006 Plan as of December 31, 2012:

Plan category	Number of securities to be issued upon exercise of	Weighted-average exercise price of outstanding	Number of securities remaining available for future issuance

	outstanding options, warrants and rights (a)	options, warrants and rights (b)	under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units	50,759	n/a	
Equity compensation plans approved by security holders unit options	929,939	$ 20.75	
Equity compensation plans approved by security holders Total	980,698		977,839

Table of Contents

The following table contains information about the ATLS 2010 Plan as of December 31, 2012:

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	2,044,227	n/a	
Equity compensation plans approved by security holders unit options	2,504,703	$ 20.51	
Equity compensation plans approved by security holders Total	4,548,930		1,189,736

180

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. These costs and expenses are limited to $1.8 million for the twelve months following February 17, 2011. We reimbursed our General Partner and its affiliates $3.8 million for the year ended December 31, 2012 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 $0.4 million in compression and gathering fees for the year ended December 31, 2012.

In June 2012, we acquired a gas gathering system and related assets in the Barnett Shale play in Tarrant County, Texas. The system consists of 19 miles of gathering pipeline that is used to facilitate gathering some of the newly-acquired production ARP. By virtue of the acquisition, we became party to a management and operating services agreement (which had been negotiated and was in existence between unaffiliated third parties prior to the acquisition), whereby ARP operated the gathering system on our behalf and we paid management and operating fees of approximately $39 thousand during the year ended December 31, 2012 to cover ARP s cost of services. The agreement was terminated in the fourth quarter of 2012.

We have agreed to provide design, procurement and construction management services for ARP with respect to a pipeline to be located in Lycoming County, Pennsylvania. The total estimated price for the project is under $5.0 million and has been approved by our General Partner s conflicts committee in accordance with our related party transaction policy.

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.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ended December 31, 2012 and 2011 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2012	2011
Audit fees (1)	$ 1,417,000	$ 1,303,666
Tax fees (2)	91,080	115,833
All other fees		
Total aggregate fees billed	$ 1,508,080	$ 1,419,499

(1) Represents the aggregate fees recognized in 2012 and 2011 for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements, the review of financial statements included in Form 10-Q and the review of registration statements and Form 8-Ks.

(2) Represents the fees recognized in each 2012 and 2011 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 2012 and 2011.

Table of Contents

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	Securities Purchase Agreement dated November 30, 2012, by and among Cardinal Midstream, LLC, Cardinal Arkoma, Inc., Cardinal Arkoma Midstream, LLC, Cardinal Gas Treating LLC and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Securities Purchase 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.(30)
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)
4.1	Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership) (2)
4.2	8 3/4% Senior Notes Indenture dated June 27, 2008(7)
4.3	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)
4.4(a)	6 5/8% Senior Notes Indenture dated September 28, 2012(26)

4.4(a)	Supplemental Indenture dated as of December 20, 2012[33]
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]
10.1(c)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[12]
10.2	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]

Table of Contents

Exhibit No.	Description
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]
10.4	Long-Term Incentive Plan[21]
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	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan[10]
10.11	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement[10]
10.12	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010[13]
10.13	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010[20]
10.14	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[20]
10.15	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[24]
10.16	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[24]
10.17	Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011[21]
10.18	Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012[25]
10.19	Purchase Agreement dated September 25, 2012 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries listed therein, and Wells Fargo Securities, LLC, on behalf of itself and the other initial purchasers[26]
10.20	Equity Distribution Agreement dated November 5, 2012, by and between Atlas Pipeline Partners, L.P. and Citigroup Global Markets Inc.[29]
10.21(a)	Purchase Agreement, dated December 6, 2012, among Atlas Pipeline Escrow, LLC and the initial purchasers named therein[32]
10.21(b)	Purchase Agreement Joinder dated as of December 20, 2012[33]
10.22	Registration Rights Agreement, dated September 28, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein[26]
10.23	Registration Rights Agreement, dated December 20, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein [33]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Grant Thornton LLP
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[34]
101.SCH	XBRL Schema Document[34]
101.CAL	XBRL Calculation Linkbase Document[34]
101.LAB	XBRL Label Linkbase Document[34]
101.PRE	XBRL Presentation Linkbase Document[34]
101.DEF	XBRL Definition Linkbase Document[34]

(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 June 27, 2008.
(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 annual report on Form 10-K filed for the year ended December 31, 2009.
(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 annual report on Form 10-K filed for the year ended December 31, 2011.
(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 September 28, 2012.
(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 December 4, 2012.
(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 10, 2012.
(33) Previously filed as an exhibit to current report on Form 8-K filed on December 26, 2012.
(34) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. 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 28, 2013

By: /s/ EUGENE N. DUBAY
Chief Executive Officer, President 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 28, 2013.

/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, President 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