ATLAS PIPELINE PARTNERS LP
Form 10-K
February 24, 2012

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, 2011

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

Pittsburg, 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. ¨

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 $32.96 per common limited partner unit on June 30, 2011, was approximately $1,564.0 million.

The number of common units of the registrant outstanding on February 20, 2012 was 53,618,095

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-K

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, natural gas liquids and condensate;*
- *the price volatility of natural gas, natural gas liquids 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.

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 considered to be a non-GAAP measurement.
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
IFRS	International Financial Reporting Standards
Keep-Whole	Contract with 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)	Contract with natural gas producers 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

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 and processing services in the Anadarko 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. , formerly known as Atlas Pipeline Holdings, L.P., (ATLS), a publicly traded Delaware limited partnership (NYSE: ATLS), which owned a 10.7% limited partner interest in us at December 31, 2011, as well as the 2% general partner interest.

The following chart displays the corporate organizational structure as of December 31, 2011:

Recent Developments

Laurel Mountain Sale

On February 17, 2011, we completed the sale (the Laurel Mountain Sale) of our 49% non-controlling interest in Laurel Mountain Midstream, LLC joint venture (Laurel Mountain) to Atlas Energy Resources, LLC (Atlas Energy Resources) for $409.5 million in cash, net of expenses and adjustments based on capital contributions we made to and distributions we received from Laurel Mountain after January 1, 2011. We retained the preferred distribution rights under the limited liability company agreement of Laurel Mountain entitling APL Laurel Mountain LLC, our wholly-owned subsidiary, to receive all payments made under a note issued to Laurel Mountain by Williams Laurel Mountain, LLC in connection with the formation of Laurel Mountain. The note was paid in full as of December 31, 2011.

AHD Transaction Agreement

Concurrently with the Laurel Mountain Sale, ATLS completed a transaction agreement (the AHD Transaction Agreement or AHD Transactions), with Atlas Energy, Inc. (AEI), a formerly publicly-traded company, and Atlas Energy Resources, a wholly-owned subsidiary of AEI, pursuant to which among other things (1) ATLS purchased certain assets from AEI; (2) AEI contributed ATLS general partner, Atlas Energy, GP, LLC (formerly known as Atlas Pipeline Holdings GP, LLC) to ATLS, so that Atlas Energy GP, LLC became ATLS wholly-owned subsidiary; and (3) AEI distributed to its stockholders all ATLS common units it held.

Atlas Energy, Inc. Merger

Concurrently with the AHD Transactions, AEI completed an agreement and plan of merger with Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), pursuant to which, among other things, AEI became a wholly-owned subsidiary of Chevron (the Chevron Merger). As part of the Chevron Merger, Chevron acquired 1,112,000 of our common units and our 12% cumulative Class C preferred units (Class C Preferred Units), which were held directly by AEI.

Atlas Pipeline Holdings, L.P. Name and Ticker Symbol Change

On February 18, 2011, subsequent to the AHD Transactions and the Chevron Merger, Atlas Pipeline Holdings, L.P. changed its name to Atlas Energy, L.P. On April 28, 2011, Atlas Energy, L.P. changed the ticker symbol of its common units on the New York Stock Exchange from AHD to ATLS , the former ticker symbol of Atlas Energy, Inc.

West Texas LPG Pipeline Acquisition

On May 11, 2011, we acquired a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) from Buckeye Partners, L.P. (NYSE: BPL) for $85.0 million. 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.

Gas Plant Expansion Projects

On May 12, 2011, we announced planned major expansions to our existing gas gathering and processing systems, including (1) a $175.0 million expansion of the Waynoka plant on our WestOK system, (2) a $75.0 million expansion of our Velma system, (3) a $15.0 million re-start of the cryogenic skid at the Midkiff plant in our WestTX system, and (4) an additional $50.0 million in growth capital for compression, gathering lines and connections that are expected to be incurred in 2012.

On November 15, 2011, we announced plans to construct a new 200 MMCFD cryogenic processing plant within our WestTX system, to be known as the Driver plant. The plant is planned to be constructed in two phases, with the first phase consisting of a 100 MMCFD processing plant expected to be in service in the first quarter of 2013. The second phase, to increase the plant capacity to 200 MMCFD, is scheduled to be complete in the first quarter of 2015.

Class C Preferred Units Redemption

On May 27, 2011, we redeemed our 8,000 units of Class C Preferred Units for cash at the liquidation value of $1,000 per unit, or $8.0 million plus $0.2 million accrued dividends. There are no longer any Class C Preferred Units outstanding.

General

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Gathering and Processing and Pipeline Transportation.

Due to the Laurel Mountain Sale and our acquisition of a 20% interest in WTLPG (see Recent Developments), we realigned the management of our business in the midstream segment of the natural gas industry from our previously reportable segments of Mid-Continent and Appalachia into the two new reportable segments.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to our 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. 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 seven natural gas processing plants with aggregate capacity of approximately 610 MMCFD, which are connected to approximately 9,000 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas. In addition, we own and operate approximately 100 miles of active natural gas gathering systems located in Tennessee. Our gathering systems gather gas from wells and central delivery points and deliver to natural gas 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, Woodford Shale, Hugoton field in the Anadarko Basin and the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin. Our gathering systems are connected to approximately 7,400 central delivery points or wells. Thus, we believe we have significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering and processing assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Our Pipeline Transportation operations consist of a 20% interest in WTLPG, which was acquired on May 11, 2011 (see Recent Developments). 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.

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 may have excess capacity, which provides us with opportunities to connect and process new supplies of natural gas with minimal additional capital requirements, also increasing plant efficiency and economics. We plan to accomplish this goal 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. Other opportunities include pursuing relationships with new producers; the elimination of 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. Our planned 200 MMCFD expansion of the Waynoka processing plant in WestOK; our recommissioning of the 60 MMCFD Midkiff plant in WestTX; and our planned construction of the 200 MMCFD Driver plant in WestTX are examples of executing this strategy. We also plan to pursue strategic acquisitions accretive to our unitholders by seeking opportunities that leverage our existing asset base, employees and existing customer relationships. 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 risk management activities are designed to reduce the effect of commodity price volatility related to future sales of natural gas, NGLs and condensate, while allowing us to meet our debt service requirements; fund our maintenance capital program; and meet our distribution objectives.

Maintaining our financial flexibility. We intend to maintain a capital structure in which we do not significantly exceed equal amounts of debt and equity on a long-term basis, while not jeopardizing our ability to achieve our other business strategies. 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 processing 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 will maximize the total throughput from all connected wells.

While natural gas produced in some areas does not require treatment 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.

Contracts and Customer Relationships

Our principal revenue is generated from the gathering, processing and sale of natural gas, NGLs and condensate and the transportation of NGLs. Primary contracts are Fee-Based, POP and Keep-Whole (see Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Revenue Arrangements).

Our Gathering and Processing Operations

We own and operate approximately 9,100 miles of intrastate natural gas gathering systems located in Oklahoma, Kansas, Texas and Tennessee. We also own and operate seven natural gas processing plants located in Oklahoma and Texas. Our gathering and processing 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 and processing systems have approximately 7,400 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 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 Enterprise Partners, L.P.; ONEOK Hydrocarbon, L.P. and WTLPG.

Gathering Systems

WestOK. The WestOK gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. The gathering system has approximately 4,700 miles of active natural gas gathering pipelines with approximately 3,700 receipt points. The primary producers on the WestOK gathering system include Chesapeake Energy Corporation; SandRidge Exploration and Production, LLC; and Bluestem Marketing, LLC.

WestTX. The WestTX gathering system, which we operate, and in which we have an approximate 72.8% ownership, has approximately 3,100 miles of active natural gas gathering pipelines and approximately 2,900 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 Pioneer; COG Operating, LLC; and Endeavor Energy Resources, LP.

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 Chesapeake Energy Corporation; Range Resources Corporation; and XTO Energy, Inc.

Tennessee. The Tennessee gathering systems are located in the Appalachian Basin. The gathering systems have approximately 100 miles of natural gas gathering pipelines, with approximately 200 receipt points. A substantial portion of the natural gas we gather in Tennessee is derived from wells operated by Atlas Energy Resources. We have a gas gathering agreement with Atlas Energy Resources, which is intended to maximize the use of the gathering systems and the amount of natural gas we gather in the region. In addition, other natural gas producers have acreage positions in relatively close proximity to our assets.

Processing and Treating Plants

WestOK. The WestOK system processes natural gas through the Waynoka and Chester plants, which are active cryogenic natural gas processing facilities. The WestOK system s processing operations have total name-plate capacity of approximately 258 MMCFD. The Waynoka processing plant, a 200 MMCFD plant located in Woods County, Oklahoma, began operations in December 2006. The Chester plant, a 28 MMCFD plant located in Woodward County, Oklahoma, began operations in 1981. A new 30 MMCFD refrigeration plant has been constructed at the Chaney Dell plant site and was placed in operation in January 2012. A new 200 MMCFD cryogenic plant has been purchased and is being installed at the Waynoka site and is expected to be operational in mid-2012. The addition of this plant will increase the WestOK name-plate capacity to approximately 458 MMCFD. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Waynoka, Chester and Chaney Dell plants and sell NGL production to ONEOK Hydrocarbon, L.P.

WestTX. The WestTX system processes natural gas through the Consolidator, Midkiff and Benedum processing plants. The Consolidator plant is a 150 MMCFD cryogenic facility in Reagan County, Texas. The facility started operations in November 2009 and replaced the Midkiff plant. The Midkiff plant is a 60 MMCFD cryogenic facility in Reagan County, Texas, which was recommissioned in 2011. The Benedum plant is a 45 MMCFD cryogenic facility in Upton County, Texas. Our WestTX processing operations have an aggregate processing name-plate capacity of approximately 255 MMCFD. We plan to construct a new 200 MMCFD cryogenic processing plant, to be known as the Driver plant, which will be constructed in two phases, with the first phase consisting of 100 MMCFD of processing capacity expected to be in service in the first quarter of 2013. The second phase will increase the plant s capacity to 200 MMCFD and is scheduled to be operational in the first quarter of 2015. The additional plant will increase the WestTX aggregate processing name-plate capacity to approximately 455 MMCFD. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the WestTX plants and sell NGL production to ONEOK Hydrocarbon, L.P.

Velma. The Velma processing plant, located in Stephens County, Oklahoma, is a cryogenic facility with a natural gas name-plate capacity of approximately 100 MMCFD. An expansion of 60 MMCFD is planned to be completed in mid-2012, which will increase name-plate capacity to 160 MMCFD. 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. We have made capital expenditures at the facility to improve its efficiency and competitiveness, including installing electric-powered compressors rather than natural gas-powered compressors used by many of our competitors. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbon, L.P.

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, treating, 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 relationships with several of our producers, some going back over 20 years. Several of our top producers have contracts with primary terms running into 2018 and beyond. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions. When we acquired control of the WestTX system in July 2007, we and Pioneer agreed to extend the existing gas sales and purchase agreement to 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.

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 pricing points. The Velma plant has access to ONEOK Gas Transportation, LLC, Southern Star Central Gas Pipeline, Inc. and Natural Gas Pipeline Company of America. The Chaney Dell and Chester plants have access to Panhandle Eastern Pipe Line Company, LP. The Waynoka plant has access to Enogex LLC, Panhandle Eastern Pipe Line Company, LP and Southern Star Central Gas Pipeline, Inc. The WestTX plants have access to Kinder Morgan Texas Pipeline, Northern Natural Gas Company and El Paso Natural Gas Company.

We sell our NGL production to ONEOK Hydrocarbon, L.P. under three separate agreements. The WestTX agreement has a term expiring in 2013; the WestOK agreement has a term expiring in 2014; and the Velma agreement has a term expiring at the end of 2016. We have signed agreements with DCP NGL Services, LLC (DCP), a subsidiary of DCP Midstream, LLC, to sell our NGL production from each of our processing facilities upon the expiration of each of the ONEOK Hydrocarbon, L.P. agreements. The DCP agreements each have a term of fifteen years. All NGL agreements are priced at the average daily Oil Price Information Service (or OPIS) price for the month for the selected market, subject to reduction by a Base Differential and quality adjustment fees.

Condensate is collected at the Velma gas plant and gathering system and currently sold to EnerWest Trading Company, LLC. Condensate collected at the WestOK plants and around the WestOK system is currently sold to Plains Marketing. Condensate collected at the WestTX plants and around the WestTX gathering system is currently sold to Plains Marketing, Occidental Energy Marketing, Inc. and Oasis Marketing and Transportation Corporation.

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 and NGLs, including 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 risk management program, which employs a variety of financial tools. The resulting combination of the underlying physical business and the commodity risk management program attempts to convert the physical price environment that consists of floating prices to a risk-managed environment characterized by fixed prices; floor prices on products where we are long the commodity price; and ceiling prices on products where we are short the commodity price. There are also risks inherent within risk management programs, including among others (1) price relationship between the physical and financial instrument deteriorating or (2) projected physical volumes changing.

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 being net long physical 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 or sale of 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 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 daily closing New York Mercantile Exchange

(NYMEX) prices when applicable and 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 and a summary of our outstanding derivative instruments as of December 31, 2011, please see Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Our Pipeline Transportation Operations

Our Pipeline Transportation operations consist of a 20% interest in WTLPG, which 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.

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 midstream assets.

Gathering and Processing. In our Gathering and Processing segment, we compete for the acquisition of well connections with several other gathering/processing operations. These operations include plants and gathering systems operated by Carrera Gas Company; Copano Energy, LLC; Crosstex

Energy Services; DCP Midstream, LLC; Enogex, LLC; Hiland Partners, L.P.; Lumen Midstream Partners, LLC; Mustang Fuel Corporation; ONEOK Field Services Company; SemGas, L.P.; Southern Union Company; Superior Pipeline Company, LLC; Targa Resources Partners; 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.

Pipeline Transportation. In our Pipeline Transportation 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 Enterprise Partners, L.P.; Lonestar NGL, LLC; and ONEOK Partners, L.P. The factors that typically affect our ability to compete for NGL supplies are:

- fees charged under our contracts;
- the quality and efficiency of our operations in delivering the NGLs to market;
- location of our transportation systems relative to our competitors; and
- the responsiveness to a plant operator 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.

Regulation

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 intrastate 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.

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 intrastate 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 includes provisions confirming FERC has exclusive jurisdiction over the siting of liquefied natural gas (LNG) terminals; provides for market-based rates for certain new underground natural gas storage facilities placed into service after the date of enactment; shortens depreciable life for gathering facilities; statutorily designates

FERC as the lead agency for federal authorizations and permits relating to interstate natural gas pipelines and LNG terminals; 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 LNG terminals; 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 or LNG terminal by a deadline set by FERC as lead agency. Such provisions, however, do not apply to review and authorization under the Coastal Zone Management Act of 1972. 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.

At present, we believe none of our gathering lines qualify as interstate natural gas transmission systems subject to FERC regulation under the Natural Gas Act. Accordingly, the provisions of the Energy Policy Act have only limited applicability to us, primarily in our capacity as a seller of natural gas.

Environmental Matters

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:

- restricting the way we can handle or dispose of our wastes;
- 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 remedial action to mitigate pollution conditions caused 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.

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.

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 assure 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.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the solid waste requirements of RCRA. 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 of 1980, as amended, or CERCLA, also known as Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum and natural gas are excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations we may generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the Environmental Protection Agency, or EPA, and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. There is 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 whose treatment and disposal or release of petroleum hydrocarbons or wastes was 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 wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, certain storage vessels and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. 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 potentially affect operation of our compressor engine fleet by requiring implementation of new monitoring requirements in calendar year 2013. The EPA has proposed new oil and gas regulations that will potentially affect our operations in calendar year 2012 by requiring more stringent volatile organic compound emission control. 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 likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, 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. Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters and also prohibit discharges of dredged and fill material in wetlands and other waters of the United States. Failure to comply with the requirements of the Clean Water Act could result in administrative, civil or criminal penalties as well as significant remedial obligations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation, or DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA. The NGPSA authorizes the DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases, and requires any entity that owns or operates pipeline facilities to comply with the regulations. The DOT s Pipeline and Hazardous Material Safety Administration, or PHMSA, acting through the Office of Pipeline Safety, or OPS, administers the national regulatory program to ensure safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. The OPS administers the federal pipeline safety regulations to (1) ensure safety in design, construction, inspection, testing, operation, and maintenance of pipeline facilities and (2) set out parameters for administering the pipeline safety program.

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. We believe our pipeline operations are in substantial compliance with existing PHMSA requirements, however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the PHMSA could result in additional requirements and costs.

The Pipeline Safety Improvement Act of 2002 finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transportation pipelines that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. To ensure uniform implementation of the pipeline safety program nationwide, federal/state partnerships, including the Texas Railroad Commission, the Oklahoma Corporation Commission and other state agencies, have adopted similar regulations applicable to intrastate gathering and transportation lines. Compliance with these rules has not had a materially adverse effect on our operations but there is no assurance this will continue in the future.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was signed into law. The Act directs the Secretary of Transportation to undertake a number of reviews, studies and reports in preparation for potential rulemakings applicable to pipeline facilities. The primary focus of the Act, however, is the operational safety of gas transmission and hazardous liquid transmission pipeline facilities, particularly in high consequence areas. The PHMSA is considering several safety related issues addressed 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.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans, and prolonged exposure can result in death. The gas produced 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 Gases. In October 2009, the EPA published rules in Title 40 of the Code of Federal Regulations, part 98 (40 CFR 98) requiring mandatory reporting of greenhouse gases. The rule specifies methods by which entities that produce these gases, which include Carbon Dioxide (CO_2) and Methane (CH_4), must inventory, monitor and report such gases. Compliance with this rule has resulted, and will continue to result, in higher costs of doing business. Additionally, in 2010, the EPA issued rules to regulate greenhouse gas emissions through traditional major source construction and operating permit programs. These permitting programs require consideration of and, if deemed necessary, implementation of best available control technology to reduce greenhouse gas emissions. As a result, our operations could face additional costs for emissions control and higher costs of doing business. Although we would not be impacted to a greater degree than other similarly situated gatherers and processors of natural gas or NGLs, a stringent greenhouse gas control program could result in a significant effect on our cost of doing business.

Properties

Our principal facilities consist of seven natural gas processing plants; approximately 9,100 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.

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

Gas Processing Facilities

Facility	Location	Year Constructed	Design Throughput Capacity (MMCFD)	2011 Average Througput (MMCFD)	2011 Average Utilization Rate
Velma plant	Stephens County, OK	Updated 2003	100	98	98%
Waynoka plant	Woods County, OK	2006	200		
Chaney Dell plant	Major County, OK	2012	30		
Chester plant	Woodward County, OK	1981	28		
Total WestOK			258	254	98%
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	196	77%

Natural Gas Gathering Systems

System	Location	Approximate Active Miles of Pipe	Approximate Number of Receipt Points
WestOK	North Central Oklahoma and Southern Kansas	4,700	3,700
Velma	Southern Oklahoma and Northern Texas	1,200	600
WestTX	West Texas	3,100	2,900
Tennessee	Tennessee	100	200

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. In some of these cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. 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 our gathering systems and operate our business. ATLS employed approximately 280 people at December 31, 2011 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 Chairman and 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, Pittsburg, Pennsylvania 15275-1011, telephone number (877) 950-7473. A complete list of our filings is available on the Securities and Exchange Commission s website at www.sec.gov. Any of our filings are also available at the Securities and Exchange Commission 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.

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 and subsequently process;
- 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 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 use 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 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 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 the financial crisis include a lower level of economic activity and 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 currently 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.

Continuing instability in the financial markets, as a result of recession or otherwise, has increased 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 conditions 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 flows and ability to make required debt service payments and pay distributions could be impacted. The uncertainty and volatility surrounding the global financial system 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 2012 market prices for NGLs, natural gas and crude oil, based upon NYMEX forward price curves as of January 4, 2012, were $1.10 per gallon, $3.02 per MMBTU and $93.76 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2012 by approximately $10.8 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 have traded in a range of $75.67 per barrel to $113.93 per barrel in 2011, while Henry Hub natural gas prices have traded in a range of $2.99 per MMBTU to $4.85 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 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 price risk management strategies may fail to protect us and could reduce our gross margin and cash flows.

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

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 price using certain 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 recent adoption of derivatives legislation by the U.S. Congress 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, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. The CFTC finalized its regulations and has set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any 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 customer and we attempt to limit our credit risk by obtaining letters of credit, guarantees 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 flows 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 and processing 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 these businesses 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 and processing 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 natural gas 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 flows.

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 flows.

We may face increased competition in the future.

We face competition for well connections. Carrera Gas Company; Copano Energy, LLC; DCP Midstream, LLC; Enogex, LLC and ONEOK Field Services Company, operate competing gathering systems and processing plants in our Velma service area. DCP Midstream, LLC; Hiland Partners, L.P.; 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. 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 flows.

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 2011, Apache, Inc.; Bluestem Gas Marketing; BNK Petroleum, Inc.; Chesapeake Energy Corporation; COG Operating LLC; Endeavor Energy Resources LP; Pioneer; Range Resources Corporation; SandRidge Exploration and Production, LLC and XTO Energy Inc. 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 flows could be reduced unless we obtain comparable supplies of natural gas from other producers.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, our cash flows 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 for a specific period of 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. 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. 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. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be reduced.

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

If one or more of the pipelines or fractionation facilities to which we deliver NGLs has service interruptions, capacity limitations or otherwise cannot or will not accept the NGLs we sell or transport, and we cannot arrange for delivery to other pipelines or facilities, the amount of NGLs we process, sell or transport may be reduced. Since our revenues depend upon the volumes of NGLs we sell or transport, this could result in a material reduction in our gross margin and cash flows.

The amount of natural gas we gather or process may be reduced if the intrastate and interstate pipelines to which we deliver gas 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. If one or more of these pipelines has service interruptions, capacity limitations or otherwise cannot or will not accept the natural gas we gather, and we cannot arrange for delivery to other pipelines, local distribution companies or end users, the amount of natural gas we gather may be reduced. Since our revenues depend upon the volumes of natural gas we gather, this could result in a material reduction in our gross margin and cash flows.

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 curtailment of operations at, or closure of, any of our processing plants 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 flows could 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 executive officers. The departure of any of our 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.

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

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

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

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

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

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

- operating a significantly larger combined entity;
- the necessity of coordinating geographically disparate organizations, systems and facilities;

integrating personnel with diverse business backgrounds and organizational cultures;

consolidating operational and administrative functions;

integrating pipeline safety-related records and procedures;

integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;

the diversion of management s attention from other business concerns;

customer or key employee loss from the acquired businesses;

a significant increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

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

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 due to 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 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 involves numerous risks, including:

- we may not be able to identify suitable acquisition candidates;

- we may not be able to make acquisitions on economically acceptable terms for various reasons, including limitations on access to capital and increased competition for a limited pool of suitable assets;

- our costs in seeking to make acquisitions may be material, even if we cannot complete any acquisition we have pursued;

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

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

- we may encounter difficulties in integrating operations and systems; and

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

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

Our ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, we have financed our acquisitions and expansions through bank credit facilities, public and private debt and proceeds from equity offerings of common and preferred units. 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 could limit our ability to fund operations and pay required debt service.

We will need a portion of our cash flows 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 indenture 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.

We may issue additional units, which may increase the risk of not having sufficient available cash to make distributions at prior per unit distribution levels.

We have wide discretion to issue additional units, including units that rank senior to our common units as to quarterly cash distributions, on the terms and conditions established by our General Partner. The payment of distributions on these additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on the common units.

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 accordingly. 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.

Regulation of our gathering operations could increase our operating costs, decrease our revenues, or both.

Currently we believe our gathering and processing of natural gas is exempt from FERC regulation under the Natural Gas Act of 1938. However, the implementation of new laws or policies, or changed interpretations of existing laws, could subject our gathering and processing operations to regulation by FERC under the Natural Gas Act, the Natural Gas Policy Act, or other laws. We expect any such regulation could increase our costs, decrease our gross margin and cash flows, or both.

Even if our gathering and processing operations are 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. Among these are FERC 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 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 conditions of 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 or regulation by the Texas Railroad Commission, Oklahoma Corporation Commission or Kansas Corporation Commission become more active, 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.

PHMSA is already considering several of the natural gas pipeline safety issues addressed in the Act. On August 25, 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities. PHMSA has requested comment on whether PHMSA should: (1) re-define the term gathering line; (2) require the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; (3) establish a new, risk-based regime of safety requirements for large-diameter, high pressure gas gathering lines in rural locations; (4) enhance the requirements for internal corrosion control of gathering lines; and (5) apply its gas integrity management requirements to onshore gas gathering lines. Comments in response to this advance notice were due on January 20, 2012.

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 and 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 hazardous substances into the environment by us or the producers in our service areas.

The operations of our gathering systems, plants and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations may restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, or requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil or criminal enforcement measures, including the assessment of monetary 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 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 or 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 has 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. On November 30, 2010, the EPA published a final GHG emissions reporting rule relating to natural gas processing, transmission, storage, and distribution activities, which requires reporting beginning in 2012 for emissions occurring in 2011. Additionally, in 2010, EPA issued rules to regulate GHG emissions through traditional major source construction and operating permit programs. 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 penalties 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.

We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our future 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.

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 and processing 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;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions; and
- 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.

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. If we were to incur a significant liability for which we were not fully insured, our gross margin and cash flows would be materially reduced.

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. 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 could include, among others, the following situations:

Employees of ATLS who provide services to us may 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 uses our assets for gathering or processing services we provide. ATLS directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders 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 flows.

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.

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. 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.

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.

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 could adversely affect our ability to operate and control 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 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.

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 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: [REMOVED AND RESERVED]

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 20, 2012, the closing price for the common units was $36.06 and there were 85 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, 2011 and 2010:

	High	Low	Distributions Declared
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
2010			
Fourth Quarter	25.80	17.43	0.37
Third Quarter	18.92	8.98	0.35
Second Quarter	14.99	8.35	0.00
First Quarter	14.71	9.63	0.00

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.

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 APL s 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 year ended December 31, 2011 were $1.7 million. There were no General Partner incentive distributions paid for the year ended December 31, 2010.

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, 2011, 2010 and 2009 and at December 31, 2011 and 2010 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, 2008 and 2007 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

The selected financial data set forth in the table includes our historical consolidated financial statements, which have been adjusted to reflect the following:

We reclassified accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.

We adjusted prior period consolidated financial statements to separately present derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

	Years Ended December 31, 2011	2010[1]	2009[1] (in thousands)	2008[1]	2007[1][2]
Statements of operations data:					
Revenue:					
Natural gas and liquids sales	$ 1,268,195	$ 890,048	$ 636,231	$ 1,078,714	$ 527,094
Transportation, compression and other fees	43,799	41,093	59,075	87,442	50,695
Derivative gain (loss)[1]	(20,452)	(5,945)	(35,815)	29,741	(104,524)
Other income, net[1]	11,192	10,392	13,114	6,844	5,252
Total revenues	1,302,734	935,588	672,605	1,202,741	478,517
Costs and expenses:					
Natural gas and liquids cost of sales	1,047,025	720,215	527,730	900,460	407,994
Plant operating	54,686	48,670	45,566	47,371	22,974
Transportation and compression	833	1,061	6,657	11,249	6,235
General and administrative[3]	36,357	34,021	37,280	(2,933)	59,600
Other costs	1,040				
Depreciation and amortization	77,435	74,897	75,684	71,764	34,453
Goodwill and other asset impairment loss			10,325	615,724	
Interest[1]	31,603	87,273	101,309	87,422	59,017
Total costs and expenses	1,248,979	966,137	804,551	1,731,057	590,273
Equity income in joint venture	5,025	4,920	4,043		
Gain (loss) on asset sales and other[4]	256,272	(10,729)	108,947		
Gain (loss) on early extinguishment of debt[1]	(19,574)	(4,359)	(2,478)	17,420	(4,972)
Income (loss) from continuing operations	295,478	(40,717)	(21,434)	(510,896)	(116,728)
Income (loss) from discontinued operations	(81)	321,155	84,148	(93,802)	(23,641)
Net income (loss)	295,397	280,438	62,714	(604,698)	(140,369)
(Income) loss attributable to non-controlling interests[5]	(6,200)	(4,738)	(3,176)	22,781	(3,940)
Preferred unit dividend effect					(3,756)
Preferred unit imputed dividend cost				(505)	(2,494)
Preferred unit dividends	(389)	(780)	(900)	(1,769)	
Net income (loss) attributable to common limited partners and the General Partner	$ 288,808	$ 274,920	$ 58,638	$ (584,191)	$ (150,559)

	Years Ended December 31,				
	2011	2010	2009	2008	2007[2]
	(in thousands, except per unit data)				
Allocation of net income (loss) attributable to:					
Common limited partner interest:					
Continuing operations	$ 281,449	$ (45,347)	$ (24,997)	$ (503,533)	$ (139,905)
Discontinued operations	(79)	315,021	82,457	(91,917)	(23,166)
	281,370	269,674	57,460	(595,450)	(163,071)
General Partner interest:					
Continuing operations	7,440	(888)	(513)	13,144	12,987
Discontinued operations	(2)	6,134	1,691	(1,885)	(475)
	7,438	5,246	1,178	11,259	12,512
Net income (loss) attributable to:					
Continuing operations	288,889	(46,235)	(25,510)	(490,389)	(126,918)
Discontinued operations	(81)	321,155	84,148	(93,802)	(23,641)
	$ 288,808	$ 274,920	$ 58,638	$ (584,191)	$ (150,559)
Net income (loss) attributable to common limited partners per unit:					
Basic:					
Continuing operations	$ 5.22	$ (0.85)	$ (0.52)	$ (11.80)	$ (5.74)
Discontinued operations		5.92	1.71	(2.16)	(0.95)
	$ 5.22	$ 5.07	$ 1.19	$ (13.96)	$ (6.69)
Diluted[6]:					
Continuing operations	$ 5.22	$ (0.85)	$ (0.52)	$ (11.80)	$ (5.74)
Discontinued operations		5.92	1.71	(2.16)	(0.95)
	$ 5.22	$ 5.07	$ 1.19	$ (13.96)	$ (6.69)
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 1,567,828	$ 1,341,002	$ 1,327,704	$ 1,415,517	$ 1,258,602
Total assets	1,930,812	1,764,848	2,137,963	2,413,196	2,875,451
Total debt, including current portion	524,140	565,974	1,254,183	1,493,427	1,229,426
Total equity	1,236,228	1,041,647	723,527	650,842	1,271,797
Cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 102,867	$ 106,427	$ 55,853	$ (59,194)	$ 100,444
Investing activities	67,763	594,753	241,123	(292,944)	(2,024,643)
Financing activities	(170,626)	(702,037)	(297,400)	341,242	1,935,059
Other financial data (unaudited):					
Gross margin from continuing operations [7]	$ 264,923	$ 210,580	$ 163,677	$ 273,493	$ 167,525
EBITDA [8]	398,235	450,543	256,368	(409,397)	(36,773)
Adjusted EBITDA [8]	181,026	209,799	174,808	322,515	183,496
Maintenance capital expenditures	$ 18,247	$ 10,921	$ 3,750	$ 4,787	$ 6,383
Expansion capital expenditures	227,179	35,715	106,524	176,869	40,268
Total capital expenditures	$ 245,426	$ 46,636	$ 110,274	$ 181,656	$ 46,651

	Years Ended December 31,				
	2011	2010	2009	2008	2007(2)
Operating data (unaudited):					
Velma system:					
Gathered gas volume (MCFD)	103,328	84,455	76,378	63,196	62,497
Processed gas volume (MCFD)	98,126	78,606	73,940	60,147	60,549
Residue Gas volume (MCFD)	80,330	64,138	58,350	47,497	47,234
NGL volume (BPD)	11,433	9,218	8,232	6,689	6,451
Condensate volume (BPD)	423	416	377	280	225
WestOK system(9):					
Gathered gas volume (MCFD)	268,329	228,684	270,703	276,715	259,270
Processed gas volume (MCFD)	254,394	214,695	215,374	245,592	253,523
Residue Gas volume (MCFD)	230,907	193,200	228,261	239,498	221,066
NGL volume (BPD)	13,635	12,395	13,418	13,263	12,900
Condensate volume (BPD)	898	697	824	791	572
WestTX system(9):					
Gathered gas volume (MCFD)	212,775	178,111	159,568	144,081	147,240
Processed gas volume (MCFD)	196,412	163,475	149,656	135,496	141,568
Residue Gas volume (MCFD)	133,857	105,982	101,788	92,019	94,281
NGL volume (BPD)	29,052	26,678	21,261	19,538	20,618
Condensate volume (BPD)	1,500	1,289	1,265	1,142	1,346
Tennessee system					
Average throughput volume (MCFD)	7,698	8,740	7,907	1,951	

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt and the separate presentation of derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

(2) Includes our acquisition of control of a 100% interest in the WestOK natural gas gathering system and processing plants and a 72.8% undivided joint interest in the WestTX natural gas gathering system and processing plants on July 27, 2007, representing approximately five months operations for the year ended December 31, 2007. Operating data for the WestOK and WestTX systems represent 100% of its operating activity.

(3) Includes non-cash compensation (income) expense of $3.3 million, $3.5 million, $0.7 million, ($34.0) million and $36.3 million for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively.

(4) 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 3).

(5) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems, which we acquired on July 27, 2007.

(6) For the years ended December 31, 2010, 2009, 2008 and 2007, approximately 300,000, 82,000, 146,000 and 164,000 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 years ended December 31, 2008 and 2007, 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.

(7) We define gross margin from continuing operations as natural gas and liquids sales and transportation, compression and other fees less purchased product costs. Product costs include the cost of natural gas and NGLs we purchase from third parties, subject to certain non-cash adjustments. 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 our revenues and costs to gross margin from continuing operations (in thousands):

RECONCILIATION OF GROSS MARGIN FROM CONTINUING OPERATIONS

	Years Ended December 31,				
	2011	**2010**	**2009** (in thousands)	**2008**	**2007[2]**
Revenue:					
Natural gas and liquids sales	$ 1,268,195	$ 890,048	$ 636,231	$ 1,078,714	$ 527,094
Transportation, compression and other fees	43,799	41,093	59,075	87,442	50,695
Total revenues for gross margin	1,311,994	931,141	695,306	1,166,156	577,789
Natural gas and liquids cost of sales	(1,047,025)	(720,215)	(527,730)	(900,460)	(407,994)
Adjustments:					
Non-cash linefill loss (gain) [10]	(46)	(346)	(3,899)	7,797	(2,270)
Gross margin	$ 264,923	$ 210,580	$ 163,677	$ 273,493	$ 167,525

(8) 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 (see Item 8: Financial Statements and Supplementary Data Note 11). 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 EBITDA and 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 (see Item 8: Financial Statements and Supplementary Data Note 13) calculation utilized within our financial covenants under our credit facility, with the exception that Adjusted EBITDA includes (1) EBITDA from the discontinued operations related to the sale of Elk City; (2) the unrecognized economic impact of WestOK and WestTX acquisition, and (3) other non-cash items specifically excluded under our credit facility.

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as their 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):

RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

	Years Ended December 31,				
	2011	**2010[1]**	**2009[1]** (in thousands)	**2008[1]**	**2007[1][2]**
Net income (loss)	$ 295,397	$ 280,438	$ 62,714	$ (604,698)	$ (140,369)
Adjustments:					
(Income) loss attributable to non-controlling interests from continuing operations[5]	(6,200)	(4,738)	(3,176)	22,781	(3,940)
Interest expense	31,603	87,273	101,309	87,422	59,017
Other interest		604	443		
Depreciation and amortization	77,435	74,897	75,684	71,764	34,453
Discontinued operations interest expense, depreciation and amortization		12,069	19,394	13,334	14,066
EBITDA	$ 398,235	$ 450,543	$ 256,368	$ (409,397)	$ (36,773)

RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

	Years Ended December 31,				
	2011	2010(1)	2009(1)	2008(1)	2007(1)(2)
			(in thousands)		
EBITDA	$ 398,235	$ 450,543	$ 256,368	$ (409,397)	$ (36,773)
Adjustments:					
Equity income in joint venture	(5,025)	(4,920)	(4,043)		
Distributions from joint venture	4,448	11,066	4,310		
Unrecognized economic impact of WestOK and WestTX acquisition(11)					10,423
Long-lived asset impairment loss			10,325		
Goodwill impairment loss, net of associated non-controlling interest				585,053	
Gain on asset sales and other(12)	(256,191)	(301,373)	(162,518)		
Loss on early extinguishment of debt	19,574	4,359	2,478	2,447	4,972
Non-cash (gain) loss on derivatives	4,538	(10,166)	74,644	(113,640)	99,543
Non-recurring net cash derivative early termination expense(13)		22,401	2,260	102,146	
Premium expense on derivative instruments	12,219	21,123	9,693	3,736	
Non-cash compensation (income) expense	3,274	3,484	701	(34,010)	36,306
Non-cash line fill loss (gain) (10)	(46)	(346)	(3,899)	7,797	(2,270)
Other non-cash items(14)					1,414
Discontinued operations adjustments(15)		13,628	(15,511)	178,383	69,881
Adjusted EBITDA	$ 181,026	$ 209,799	$ 174,808	$ 322,515	$ 183,496

(9) Volumetric data for the WestOK and WestTX systems for the year ended December 31, 2007 represents volumes recorded for the 158-day period from July 27, 2007, the date of our acquisition, through December 31, 2007.

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

(11) The acquisition of the WestOK and WestTX systems was consummated on July 27, 2007, although the acquisition s effective date was July 1, 2007. As such, we receive the economic benefits of ownership of the assets as of July 1, 2007. However, in accordance with generally accepted accounting principles, we have only recorded the results of the acquired assets commencing on the closing date of the acquisition. The economic benefits of ownership we received from the acquired assets from July 1 to July 27, 2007 were recorded as a reduction of the consideration paid for the assets.

(12) For the year-ended December 31, 2011, includes the gain on the sale of our non-controlling interest in Laurel Mountain. For the year ended December 31, 2010, includes the gain on the sale of Elk City 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.

(13) 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. These derivative contracts were put into place simultaneously with our acquisition of the WestOK and WestTX systems in July 2007. The 2008 settlements were funded through our June 2008 issuance of 5.75 million common limited partner units in a public offering and issuance of 1.39 million common limited partner units to Atlas Energy, L.P. and Atlas Energy, Inc. in a private placement. In connection with this transaction, we also 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.

(14) Includes the cash proceeds received from the sale of Enville plant and the non-cash loss recognized within our statements of operations.

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

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

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

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering and processing services in the Anadarko 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.

Due to the sale of our 49% non-controlling interest in Laurel Mountain Midstream, LLC (Laurel Mountain), a Delaware limited liability company, and our acquisition of a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) (see Recent Events), we realigned the management of our business in the midstream segment of the natural gas industry into two new reportable segments: Gathering and Processing; and Pipeline Transportation.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to our 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering and processing of natural gas.

Our Gathering and Processing operations, own, have interests in and operate seven natural gas processing plants with aggregate capacity of approximately 610 MMCFD, which are connected to approximately 9,000 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas. In addition, we own and operate approximately 100 miles of active natural gas gathering systems located in Tennessee. Our gathering systems gather gas from wells and central delivery points and deliver to natural gas processing plants, as well as third-party pipelines.

Our Pipeline Transportation operations consist of a 20% interest in WTLPG, which was acquired on May 11, 2011 (see Recent Events). 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 Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest.

Recent Events

On February 17, 2011, we completed the sale to Atlas Energy Resources, LLC of our 49% non-controlling interest in Laurel Mountain (the Laurel Mountain Sale) for $409.5 million in cash, net of expenses and adjustments based on certain capital contributions we made to and distributions we received from Laurel Mountain after January 1, 2011. We utilized the proceeds from the sale to repay our indebtedness, to fund capital expenditures, and for general corporate purposes. We retained the preferred distribution rights under the limited liability company agreement of Laurel Mountain entitling APL Laurel Mountain, LLC, our wholly-owned subsidiary, to receive all payments made under a $25.5 million note issued to Laurel Mountain by Williams Laurel Mountain, LLC in connection with the formation of Laurel Mountain. The $8.5 million remaining balance of the note was paid by Williams in December 2011.

On April 7, 2011, we purchased $7.2 million, or 3.24%, of the outstanding 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes), which represented all the 8.75% Senior Notes validly tendered pursuant to our offer to purchase the 8.75% Senior Notes, at par, and paid $0.2 million in accrued and unpaid interest for a total payment of $7.4 million (see Senior Notes). We funded the purchase from a portion of the net proceeds from the sale of our 49% non-controlling interest in Laurel Mountain.

On April 8, 2011, we redeemed all our 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) for a total redemption of $293.7 million, including accrued interest of $7.0 million and premium of $11.2 million (see Senior Notes). We funded the redemption with a portion of the net proceeds from the sale of our 49% non-controlling interest in Laurel Mountain.

On May 11, 2011, we acquired a 20% interest in WTLPG from Buckeye Partners, L.P. for $85.0 million. 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 and is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest.

On May 12, 2011, we announced planned major expansions to our existing gas gathering and processing systems including, (1) a $175.0 million expansion of our WestOK system; (2) a $75.0 million expansion of our Velma system; (3) a $15.0 million re-start of the cryogenic skid at the Midkiff plant in our WestTX system; and (4) an additional $50.0 million in growth capital for compression, gathering lines and connections that are expected to be incurred in 2012.

On May 27, 2011, we redeemed our 8,000 units of Class C Preferred Units for cash at the liquidation value of $1,000 per unit, or $8.0 million plus $0.2 million accrued dividends. There are no longer any Class C Preferred Units outstanding (see Preferred Units).

On July 8, 2011, we exercised the $100.0 million accordion feature on our revolving credit facility to increase the capacity from $350.0 million to $450.0 million. The other terms of the credit agreement remain unchanged.

On July 15, 2011, we amended an operating lease for eight compressors to include a mandatory purchase of the equipment at the end of the term of the lease, thereby converting the agreement into a capital lease upon the effective date of the amendment, and capitalized $11.4 million within property plant and equipment with an offsetting liability within debt on our consolidated balance sheets based on the minimum payments required under the lease and our incremental borrowing rate.

On August 29, 2011, we signed long-term product sales agreements with DCP NGL Services, LLC (DCP), a subsidiary of DCP Midstream, LLC, to sell our NGL production from each of our processing facilities in Oklahoma and Texas. The agreements are based on Mt. Belvieu NGL pricing and each has a term of fifteen years, which will become effective at various times upon expiration of our existing NGL sales agreements.

On November 15, 2011, we announced plans to construct a new 200 MMCFD cryogenic processing plant within our WestTX system, to be known as the Driver plant. The plant is planned to be constructed in two phases, with the first phase consisting of a 100 MMCFD processing plant expected to be in service in the first quarter of 2013. The second phase, to increase the plant capacity to 200 MMCFD, is scheduled to be complete in the first quarter of 2015.

On November 21, 2011, we issued $150.0 million of our 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% (see Senior Notes). 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.

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 (see Recent Events).

Dispositions

On May 4, 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra) for net proceeds of $294.5 million in cash, net of working capital adjustments, and recorded a gain of $51.1 million within discontinued operations.

On May 31, 2009, we completed the formation of Laurel Mountain, a joint venture, with subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams). Williams contributed cash of $100.0 million to the joint venture (of which we received approximately $87.8 million, net of working capital adjustments) and a note receivable of $25.5 million. We contributed our Appalachia natural gas gathering system and retained a 49% non-controlling ownership interest in Laurel Mountain. Williams obtained the remaining 51% ownership interest in Laurel Mountain. We recognized a gain on sale of $108.9 million, including $54.2 million associated with the revaluation of our investment in Laurel Mountain to fair value.

On September 16, 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.

On February 17, 2011, we completed the Laurel Mountain Sale to Atlas Energy Resources for $409.5 million in cash, net of expenses and adjustments and recognized a gain of $254.1 million (see Recent Events).

Contractual Revenue Arrangements

Our principal revenue is generated from the gathering and sale of natural gas, NGLs and condensate. Variables that affect our revenue are:

- the volumes of natural gas we gather and process, 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 and process and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent, mid-Atlantic 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 plants.

Revenue consists of the sale of natural gas and NGLs and the fees earned from our gathering and processing 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 and NGLs 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).

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 and processed.

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. While we have no definitive plans to access the capital markets, should we decide to do so in the near future, the terms, size, and cost of new debt or equity could be less favorable than in previous transactions.

Results of Operations

The following table illustrates selected pricing before the effect of derivatives and volumetric information related to our Gathering and Processing segment for the periods indicated:

	Years Ended December 31,				
	2011	2010	Percent Change	2009	Percent Change
Pricing:					
Weighted Average Prices:					
NGL price per gallon Conway hub	$ 1.08	$ 0.92	17.4%	$ 0.68	35.3%
NGL price per gallon Mt. Belvieu hub	1.31	1.03	27.2%	0.77	33.8%
Natural gas sales ($/Mcf):					
Velma	3.86	4.14	(6.8)%	3.24	27.8%
WestOK	3.87	4.13	(6.3)%	3.25	27.1%
WestTX	3.84	4.10	(6.3)%	3.35	22.4%
Weighted Average	3.86	4.12	(6.3)%	3.28	25.6%
NGL sales ($/gallon):					
Velma	1.11	0.90	23.3%	0.69	30.4%
WestOK	1.10	0.94	17.0%	0.69	36.2%
WestTX	1.33	1.02	30.4%	0.83	22.9%
Weighted Average	1.20	0.97	23.7%	0.73	32.9%
Condensate sales ($/barrel):					
Velma	94.35	78.28	20.5%	59.80	30.9%
WestOK	86.63	72.67	19.2%	55.07	32.0%
WestTX	92.84	75.57	22.9%	60.35	25.2%
Weighted Average	90.65	75.08	20.7%	58.21	29.0%
Operating data:					
Velma system:					
Gathered gas volume (MCFD)	103,328	84,455	22.3%	76,378	10.6%
Processed gas volume (MCFD)	98,126	78,606	24.8%	73,940	6.3%
Residue Gas volume (MCFD)	80,330	64,138	25.2%	58,350	9.9%
NGL volume (BPD)	11,433	9,218	24.0%	8,232	12.0%
Condensate volume (BPD)	423	416	1.7%	377	10.3%
WestOK system:					
Gathered gas volume (MCFD)	268,329	228,684	17.3%	270,703	(15.5)%
Processed gas volume (MCFD)	254,394	214,695	18.5%	215,374	(0.3)%
Residue Gas volume (MCFD)	230,907	193,200	19.5%	228,261	(15.4)%
NGL volume (BPD)	13,635	12,395	10.0%	13,418	(7.6)%
Condensate volume (BPD)	898	697	28.8%	824	(15.4)%
WestTX system[(1)]:					
Gathered gas volume (MCFD)	212,775	178,111	19.5%	159,568	11.6%
Processed gas volume (MCFD)	196,412	163,475	20.1%	149,656	9.2%
Residue Gas volume (MCFD)	133,857	105,982	26.3%	101,788	4.1%
NGL volume (BPD)	29,052	26,678	8.9%	21,261	25.5%
Condensate volume (BPD)	1,500	1,289	16.4%	1,265	1.9%
Tennessee system:					
Average throughput volumes (MCFD)	7,698	8,740	(11.9)%	7,907	10.5%

(1) Operating data for the WestTX system represents 100% of its operating activity.

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

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

	Years Ended December 31, 2011	2010(1)	Variance	Percent Change
Revenues:				
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%
Derivative loss, net	(20,452)	(5,945)	(14,507)	(244.0)%
Other income, net	11,192	10,392	800	7.7%
Total Revenues	$ 1,302,734	$ 935,588	$ 367,146	39.2%

(1) Adjusted to reflect the separate presentation of derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

Natural gas and liquids sales 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 Natural Resources Company (NYSE: PXD) as a result of their continued drilling program.

Derivative loss, net had an unfavorable variance for the year ended December 31, 2011 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 recorded to derivative loss, net instead of natural gas liquids sales as a result of the discontinuance of hedge accounting in prior years. 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 Item 8: Financial Statements and Supplementary Data Note 11).

Costs and Expenses. The following table details the variances between the years ended 2011 and 2010 for costs and expenses (in thousands):

	Years Ended December 31, 2011	2010(1)	Variance	Percent Change
Costs and Expenses:				
Natural gas and liquids cost of sales	$ 1,047,025	$ 720,215	$ 326,810	45.4%
Plant operating	54,686	48,670	6,016	12.4%
Transportation and compression	833	1,061	(228)	(21.5)%
General and administrative	36,357	34,021	2,336	6.9%
Other costs	1,040		1,040	100.0%
Depreciation and amortization	77,435	74,897	2,538	3.4%
Interest expense	31,603	87,273	(55,670)	(63.8)%
Total Costs and Expenses	$ 1,248,979	$ 966,137	$ 282,842	29.3%

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.

Natural gas and liquids cost of sales for the year ended December 31, 2011 increased due to an increase in average commodity prices and processed volumes in comparison to the prior year period, as discussed above in Revenues.

Plant 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.

Transportation and compression expenses for the year ended December 31, 2011 decreased due to lower throughput volumes on the Tennessee gathering system.

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 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. 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 Recent Events).

Other income items. The following table details the variances between the years ended 2011 and 2010 for other income items (in thousands):

	Years Ended December 31			Percent
	2011	**2010(1)**	**Variance**	**Change**
Equity income in joint ventures	$ 5,025	$ 4,920	$ 105	2.1%
Gain (loss) on asset sales and other	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	(6,200)	(4,738)	(1,462)	(30.9)%

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.

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 (see Recent Events), 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 Recent Events).

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 Recent Events).

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 (see Recent Events). 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.

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.

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 Petroleum Corporation s (Anadarko NYSE: APC) interest in the net income of the WestOK and WestTX joint ventures.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenue. The following table details the variances between the years ended 2010 and 2009 for revenues (in thousands):

	Years Ended December 31,			Percent
	2010(1)	2009(1)	Variance	Change
Revenues:				
Natural gas and liquids sales	$ 890,048	$ 636,231	$ 253,817	39.9%
Transportation, processing and other fees	41,093	59,075	(17,982)	(30.4)%
Derivative loss, net	(5,945)	(35,815)	29,870	83.4%
Other income, net	10,392	13,114	(2,722)	(20.8)%
Total Revenues	$ 935,588	$ 672,605	$ 262,983	39.1%

(1) Adjusted to reflect the separate presentation of derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

Natural gas and liquids sales for the year ended December 31, 2010 increased primarily due to a favorable price change as a result of higher realized commodity prices, combined with lower qualified hedge losses. Gains and losses within other comprehensive income (loss), related to previously designated hedges, are recorded within natural gas and liquids sales, while all other gains and losses related to derivative instruments are recorded within derivative loss, net. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales and natural gas purchases 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.

The WestTX system s NGL production volume for the year ended December 31, 2010 increased when compared to the prior year period representing an increase in production efficiency primarily due to the start-up of the new Consolidator plant, which provides greater recoveries, increasing the liquid volumes extracted from the natural gas stream. NGL production volume on the WestOK system decreased for the year ended December 31, 2010 compared to the prior year due to a decreased number of well connects in 2010, resulting from lower capital spending. NGL production on the Velma system increased for the year ended December 31, 2010 when compared to the prior year period primarily due to increased gathered gas volume resulting from the completion of the Madill-to-Velma gas gathering pipeline.

Transportation, processing and other fee revenue decreased primarily due to a $16.9 million decrease from the Appalachia system as a result of our May 2009 contribution of the majority of the system to Laurel Mountain, a joint venture in which we had a 49% non-controlling ownership interest. After the contribution, we recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations.

Derivative loss, net had a favorable movement for the year ended December 31, 2010 due primarily to a $63.6 million favorable variance in non-cash mark-to-market adjustments on derivatives, offset by $32.3 million unfavorable variance of net cash derivative expense related to the early termination of a portion of our derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 11).

Other income, net, decreased for the year ended December 31, 2010 due primarily to a $1.8 million decrease in interest income recognized on the note receivable from Anadarko, related to their non-controlling interest in WestTX and WestOK.

Costs and Expenses. The following table details the variances between the years ended 2010 and 2009 for costs and expenses (in thousands):

	Years Ended December 31,			Percent
	2010(1)	**2009(1)**	**Variance**	**Change**
Costs and Expenses:				
Natural gas and liquids cost of sales	$ 720,215	$ 527,730	$ 192,485	36.5%
Plant operating	48,670	45,566	3,104	6.8%
Transportation and compression	1,061	6,657	(5,596)	(84.1)%
General and administrative	34,021	37,280	(3,259)	(8.7)%
Depreciation and amortization	74,897	75,684	(787)	(1.0)%
Goodwill and other asset impairment loss		10,325	(10,325)	(100.0)%
Interest expense	87,273	101,309	(14,036)	(13.9)%
Total Costs and Expenses	$ 966,137	$ 804,551	$ 161,586	20.1%

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.

Natural gas and liquids cost sales for the year ended December 31, 2010 increased primarily due to an increase in average commodity prices in comparison to the prior year period, as discussed above in revenues.

Transportation and compression expenses for the year ended December 31, 2010 decreased due to our contribution of the Appalachia system to Laurel Mountain.

Goodwill and other asset impairment loss for the year ended December 31, 2009 was due to an impairment of certain gas plant and gathering assets as a result of our annual review of long-lived assets.

Interest expense for the year ended December 31, 2010 decreased primarily due to a $9.5 million decrease in interest rate swap expense due to the interest rate swaps expiring in April 2010 and due to a $5.8 million decrease in interest expense associated with our term loan. The lower interest expense on our term loan is due to the retirement of the term loan in September 2010 with proceeds from the sale of Elk City.

Other income items. The following table details the variances between the years ended 2010 and 2009 for other income items (in thousands):

	Years Ended December 31			Percent
	2010(1)	2009(1)	Variance	Change
Equity income in joint venture	$ 4,920	$ 4,043	$ 877	21.7%
Gain (loss) on asset sales and other	(10,729)	108,947	(119,676)	(109.8)%
Loss on early extinguishment of debt	(4,359)	(2,478)	(1,881)	(75.9)%
Income from discontinued operations	321,155	84,148	237,007	281.7%
Income attributable to non-controlling interests	(4,738)	(3,176)	(1,562)	(49.2)%

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.

Equity income represents our ownership interest in the net income of Laurel Mountain, and it increased for the year ended December 31, 2010 as a result of the prior year including only seven months of operations.

Gain (loss) on asset sales and other for the years ended December 31, 2010 and 2009 includes amounts associated with the contribution of a 51% ownership interest in our Appalachia natural gas gathering system in 2009 and the sale of our 49% interest in Laurel Mountain in 2010.

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. Loss on early extinguishment of debt for the year ended December 31, 2009 represents the accelerated amortization of debt expense related to the early retirement of a portion of our term loan with proceeds from the sale of NOARK gas gathering and interstate pipeline, which was sold in May 2009.

Income from discontinued operations increased for the year ended December 31, 2010 primarily due to the $312.1 million gain on sale of Elk City in the current year period compared to the $51.1 million gain on sale of the NOARK gas gathering and interstate pipeline, which was sold in May 2009.

Income attributable to non-controlling interests increased for the year ended December 31, 2010 primarily due to higher net income for the WestOK and WestTX joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The increase in net income of the WestOK and WestTX joint ventures was principally due to higher gross margins on the sale of commodities resulting from higher prices. The non-controlling interest expense represents Anadarko s interest in the net income of the WestOK and WestTX joint ventures.

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, 2011, we had $142.0 million outstanding borrowings under our $450.0 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 $307.9 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, 2011. We had a working capital deficit of $39.5 million at December 31, 2011 compared with a $36.6 million working capital deficit at December 31, 2010. We believe we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flows. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

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

Cash Flows Year Ended December 31, 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,			**Percent**
	2011	**2010**	**Variance**	**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; 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 (see Recent Events); partially offset by $403.6 million net cash proceeds from the sale of Laurel Mountain (see Recent Events).

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 (see Recent Events) 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 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 (see Recent Events).

Cash Flows Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The following table details the variances between the years ended 2010 and 2009 for cash flows (in thousands):

	Years Ended December 31, 2010	2009	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 106,427	$ 55,853	$ 50,574	90.5%
Investing activities	594,753	241,123	353,630	146.7%
Financing activities	(702,037)	(297,400)	(404,637)	(136.1)%
Net change in cash and cash equivalents	$ (857)	$ (424)	$ (433)	(102.1)%

Net cash provided by operating activities for the year ended December 31, 2010 increased primarily due to a $48.8 million increase in net earnings from continuing operations, excluding non-cash charges, and a $20.6 million increase in cash flows from working capital changes, partially offset by an $18.8 million decrease in cash provided by discontinued operations. Net earnings from continuing operation, excluding non-cash charges, increased primarily due to a favorable gross margin in continuing operations of $46.9 million, mainly as a result of higher commodity prices.

Net cash provided by investing activities for the year ended December 31, 2010 increased as a result of the net proceeds of $676.8 million received from the sale of Elk City in 2010 compared to $292.0 million received from the sale of the NOARK gas gathering and interstate pipeline system in the prior year period combined with the $89.5 million received from the sale of our 51% interest in the Appalachia assets in the prior year period. Additionally, there was a $64.5 million decrease in capital expenditures compared to the prior year period (see further discussion of capital expenditures under Capital Requirements).

Net cash used in financing activities for the year ended December 31, 2010 increased mainly due to a $280.0 million net increase in repayments of the outstanding principal balance on our revolving credit facility and a $159.8 million increase in repayments of our term loan. The increase in repayments on our term loan and revolving credit facility is principally due to the retirement of the term loan and a portion of our revolving credit facility with proceeds from the sale of Elk City.

Capital Requirements

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

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Years Ended December 31,		
	2011	2010	2009
Maintenance capital expenditures	$ 18,247	$ 10,921	$ 3,750
Expansion capital expenditures	227,179	35,715	106,524
Total	$ 245,426	$ 46,636	$ 110,274

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. As of December 31, 2011, we had approved additional expenditures of approximately $159.4 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $73.2 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 decreased for the year ended December 31, 2010 primarily due to the completion of the Madill to Velma pipeline and the construction of the Consolidator gas plant in 2009, compounded by a reduction of well connects in 2010. The increase in maintenance capital expenditures for the year ended December 31, 2010 was partially due to planned maintenance expense at the Waynoka plant plus fluctuations in the timing of other scheduled maintenance activity

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 $1.7 million were paid during year ended December 31, 2011. No incentive distributions were paid during the year ended December 31, 2010.

Off Balance Sheet Arrangements

As of December 31, 2011, 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, 2011 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Total debt	$ 507,822	$	$	$ 142,000	$ 365,822
Interest on total debt[1]	224,543	36,469	72,938	68,367	46,769
Capital leases	12,126	2,685	9,441		
Operating leases	2,682	1,580	780	322	
Total contractual cash obligations	$ 747,173	$ 40,734	$ 83,159	$ 210,689	$ 412,591

(1) Based on the interest rates of our respective debt components as of December 31, 2011.

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Standby letters of credit	$ 75	$ 75	$	$	$
Purchase commitments	73,193	73,193			
Throughput contracts	22,590	8,235	14,355		
Total commercial commitments	$ 95,858	$ 81,503	$ 14,355	$	$

Common Equity Offerings

In August 2009, we sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. We also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in us. In addition, we issued warrants 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. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see Revolving Credit Facility).

On January 7, 2010, we executed amendments to the warrants, which were originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered 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 .

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.

The Class C Preferred Units received distributions of 12% per annum, paid quarterly on the same date as the distribution payment date for our common units. The record date for the determination of holders entitled to receive distributions was the same as the record date for determination of common unit holders entitled to receive quarterly distributions. We had the right to redeem some or all of the Class C Preferred Units for an amount equal to the face value of the Class C Preferred Units being redeemed plus all accrued but unpaid dividends.

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. There are no Class C Preferred Units outstanding at December 31, 2011.

Revolving Credit Facility

At December 31, 2011, we had a $450.0 million senior secured revolving credit facility with a syndicate of banks, which matures in December 2015. On July 8, 2011, the revolving credit facility was increased from $350.0 million to $450.0 million. 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, 2011, was 3.1%. 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, 2011. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

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

The events that constitute an event of default for our revolving credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. As of December 31, 2011, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

8.75% Senior Notes

At December 31, 2011, we had $371.0 million principal amount outstanding of 8.75% Senior Notes, including a net $5.2 million unamortized premium. 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 8.75% 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 8.75% Senior Notes are junior in right of payment to our secured debt, including our obligations under our revolving credit facility.

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 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 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.

The 8.75% Senior Notes sold in private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required us to file a registration statement with the SEC to exchange the privately placed notes for registered notes. We filed a registration statement with the SEC in satisfaction of the requirements of the registration rights agreement on December 12, 2011, and the registration statement was declared effective on January 13, 2012. We currently anticipate completing the exchange offer on March 5, 2012.

The indenture governing the 8.75% Senior Notes contains 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, 2011.

8.125% Senior Notes

In November 2010, we paid $1.3 million to the holders of the 8.125% Senior Notes in connection with a solicited consent received from the majority of holders of those notes to amend certain provisions of the indenture governing the 8.125% Senior Notes. The amendment allowed us to make certain capital contributions to Laurel Mountain Midstream, LLC.

On April 8, 2011, we 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. We paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. There are no 8.125% Senior Notes outstanding at December 31, 2011.

Environmental Regulation

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

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

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

Inflation and Changes in Prices

Inflation affects the operating expenses of our operations due to the increase in costs of labor and supplies. Inflation did not have a material impact on our results of operations for the years ended December 31, 2011, 2010 and 2009. 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 accounting principles generally accepted in the United States 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, 2011.

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 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, 2011, there were $68.6 million accrued unbilled revenues. A 10% change in the estimated revenues would change gross margin by approximately $1.4 million.
Impairment of Long-Lived Assets		
Management evaluates our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset is considered impaired when the estimated undiscounted cash flow from such asset is less than the asset s carrying value. In that event, a 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, 2011, 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.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
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 $5.6 million, which would result in a corresponding change in our operating income.
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 natural gas liquids sales, interest expense and/or derivative loss, net. (See Item 8: Financial Statements and Supplementary Data Note 12 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, 2011, approximately 70% 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. A 10% increase in our prices utilized in calculating the fair value of derivatives at December 31, 2011 would have decreased net income by approximately $17.3 million for the year ended December 31, 2011.

Recently Issued Accounting Standards

See Item 8. Financial Statements and Supplementary Data Note 2 Recently Issued Accounting Standards for information regarding recent 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, 2011. 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, 2011, we had a $450.0 million senior secured revolving credit facility with $142.0 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 3.1% at December 31, 2011. Based upon the outstanding borrowings on the senior secured revolving credit facility and holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately $1.4 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 4, 2012, were $1.10 per gallon, $3.02 per million BTU and $93.76 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2012 by approximately $10.8 million.

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) as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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), Atlas Pipeline Partners, L.P. s internal control over financial reporting as of December 31, 2011, 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 24, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 24, 2012

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 168	$ 164
Accounts receivable	115,412	99,759
Current portion of derivative assets	1,645	
Prepaid expenses and other	15,641	15,118
Total current assets	132,866	115,041
Property, plant and equipment, net	1,567,828	1,341,002
Intangible assets, net	103,276	126,379
Investment in joint ventures	86,879	153,358
Long-term portion of derivative assets	14,814	
Other assets, net	25,149	29,068
Total assets	$ 1,930,812	$ 1,764,848
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 2,085	$ 210
Accounts payable affiliates	2,675	12,280
Accounts payable	54,644	29,382
Accrued liabilities	23,282	30,013
Accrued interest payable	1,624	1,921
Current portion of derivative liabilities		4,564
Accrued producer liabilities	88,096	72,996
Distribution payable		240
Total current liabilities	172,406	151,606
Long-term portion of derivative liabilities		5,608
Long-term debt, less current portion	522,055	565,764
Other long-term liability	123	223
Commitments and contingencies		
Equity:		
General Partner s interest	23,856	20,066
Preferred limited partner s interest		8,000
Common limited partners interests	1,245,163	1,057,342
Accumulated other comprehensive loss	(4,390)	(11,224)
Total partners capital	1,264,629	1,074,184
Non-controlling interest	(28,401)	(32,537)
Total equity	1,236,228	1,041,647
Total liabilities and equity	$ 1,930,812	$ 1,764,848

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31		
	2011	**2010**	**2009**
Revenue:			
Natural gas and liquids sales	$ 1,268,195	$ 890,048	$ 636,231
Transportation, processing and other fees third parties	43,464	40,474	41,539
Transportation, processing and other fees affiliates	335	619	17,536
Derivative loss, net	(20,452)	(5,945)	(35,815)
Other income, net	11,192	10,392	13,114
Total revenues	1,302,734	935,588	672,605
Costs and expenses:			
Natural gas and liquids cost of sales	1,047,025	720,215	527,730
Plant operating	54,686	48,670	45,566
Transportation and compression	833	1,061	6,657
General and administrative	34,551	32,521	34,549
Compensation reimbursement affiliates	1,806	1,500	2,731
Other costs	1,040		
Depreciation and amortization	77,435	74,897	75,684
Other asset impairment loss			10,325
Interest	31,603	87,273	101,309
Total costs and expenses	1,248,979	966,137	804,551
Equity income in joint ventures	5,025	4,920	4,043
Gain (loss) on asset sale and other	256,272	(10,729)	108,947
Loss on early extinguishment of debt	(19,574)	(4,359)	(2,478)
Income (loss) from continuing operations	295,478	(40,717)	(21,434)
Discontinued operations:			
Gain (loss) on sale of discontinued operations	(81)	312,102	53,571
Earnings from discontinued operations		9,053	30,577
Income (loss) from discontinued operations	(81)	321,155	84,148
Net income	295,397	280,438	62,714
Income attributable to non-controlling interests	(6,200)	(4,738)	(3,176)
Preferred unit dividends	(389)	(780)	(900)
Net income attributable to common limited partners and the General Partner	$ 288,808	$ 274,920	$ 58,638

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2011	**2010**	**2009**
Allocation of net income (loss) attributable to:			
Common limited partner interest:			
Continuing operations	$ 281,449	$ (45,347)	$ (24,997)
Discontinued operations	(79)	315,021	82,457
	281,370	269,674	57,460
General Partner interest:			
Continuing operations	7,440	(888)	(513)
Discontinued operations	(2)	6,134	1,691
	7,438	5,246	1,178
Net income (loss) attributable to:			
Continuing operations	288,889	(46,235)	(25,510)
Discontinued operations	(81)	321,155	84,148
	$ 288,808	$ 274,920	$ 58,638
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ 5.22	$ (0.85)	$ (0.52)
Discontinued operations		5.92	1.71
	$ 5.22	$ 5.07	$ 1.19
Weighted average common limited partner units (basic)	53,525	53,166	48,299
Diluted:			
Continuing operations	$ 5.22	$ (0.85)	$ (0.52)
Discontinued operations		5.92	1.71
	$ 5.22	$ 5.07	$ 1.19
Weighted average common limited partner units (diluted)	53,944	53,166	48,299

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Years Ended December 31,		
	2011	2010	2009
Net income	$ 295,397	$ 280,438	$ 62,714
Income attributable to non-controlling interests	(6,200)	(4,738)	(3,176)
Preferred unit dividends	(389)	(780)	(900)
Net income attributable to common limited partners and the General Partner	288,808	274,920	58,638
Other comprehensive income:			
Changes in fair value of derivative instruments accounted for as cash flow hedges			(2,268)
Adjustment for realized losses reclassified to net income	6,834	37,966	58,022
Total other comprehensive income	6,834	37,966	55,754
Comprehensive income	$ 295,642	$ 312,886	$ 114,392

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, 2009	40,000	45,954,808	$ 37,860	$ 735,742	$ 14,521	$ (104,944)	$	$ (32,337)	$ 650,842
Conversion of preferred limited partner units	(5,000)	1,465,653	(2,528)	2,528					
Redemption of preferred limited partner units	(25,000)		(25,000)						(25,000)
Purchase of treasury units							(15,000)		(15,000)
Issuance of units and General Partner capital contribution	5,000	2,689,765	4,955	16,074	658				21,687
Issuance of common units under incentive plans		406,877							
Unissued common units under incentive plans				702					702
Distributions paid			(1,232)	(24,671)	(505)				(26,408)
Distributions paid to non-controlling interests								(1,764)	(1,764)
Other comprehensive income						55,754			55,754
Net income			900	57,459	1,179			3,176	62,714
Balance at December 31, 2009	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

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2011	**2010**	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 295,397	$ 280,438	$ 62,714
Less: Income (loss) from discontinued operations	(81)	321,155	84,148
Net income (loss) from continuing operations	295,478	(40,717)	(21,434)
Adjustments to reconcile net income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	77,435	74,897	75,684
Other asset impairment loss			10,325
Equity income in joint ventures	(5,025)	(4,920)	(4,043)
Distributions received from joint ventures	4,448	11,066	4,310
Non-cash compensation expense	3,274	3,484	702
Amortization of deferred finance costs	4,480	6,186	5,538
(Gain) loss on asset sales	(256,272)	2,229	(108,947)
Loss on early extinguishment of debt	19,574	4,359	2,478
Change in operating assets and liabilities:			
Accounts receivable, prepaid expenses and other	(16,216)	(21,498)	(2,686)
Accounts payable and accrued liabilities	5,093	32,906	1,197
Accounts payable and accounts receivable affiliates	(9,605)	10,237	2,580
Derivative accounts payable and receivable	(19,797)	4,824	48,007
Net cash provided by continuing operating activities	102,867	83,053	13,711
Net cash provided by discontinued operating activities		23,374	42,142
Net cash provided by operating activities	102,867	106,427	55,853
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(245,426)	(45,752)	(110,274)
Investment in joint ventures	(85,000)		
Capital contribution to joint ventures	(12,250)	(26,514)	(1,680)
Proceeds from preferred rights to note receivable	8,500		
Net proceeds (expenditures) related to asset sales	403,578	(2,229)	89,472
Other	(1,558)	56	(1,782)
Net cash provided by (used in) continuing investing activities	67,844	(74,439)	(24,264)
Net cash provided by (used in) discontinued investing activities	(81)	669,192	265,387
Net cash provided by investing activities	67,763	594,753	241,123
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	1,515,500	482,000	694,000
Repayments under credit facility	(1,443,500)	(738,000)	(670,000)
Net proceeds from issuance of long term debt	152,366		
Repayment of long term debt	(279,557)	(433,505)	(273,675)
Payment of premium on early retirement of debt	(14,342)		
Principal payments on capital lease	(954)	(142)	
Net proceeds from issuance of common limited partner units	468	15,475	16,074
Purchase and retirement of treasury units	(984)	(246)	

Net proceeds from issuance of preferred limited partner units				8,000	4,955
Redemption of preferred limited partner units		(8,000)		(15,000)	(15,000)
Purchase of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC					(15,000)
Redemption of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC				15,000	
General Partner capital contributions				331	658
Net distributions to non-controlling interest holders		(2,064)		(6,350)	(1,764)
Distributions paid to common limited partners, the General Partner and preferred limited partners		(100,313)		(19,737)	(26,408)
Other		10,754		(9,863)	(11,240)
Net cash used in financing activities		(170,626)		(702,037)	(297,400)
Net change in cash and cash equivalents		4		(857)	(424)
Cash and cash equivalents, beginning of period		164		1,021	1,445
Cash and cash equivalents, end of period	$	168	$	164	1,021

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 and processing of natural gas in the Mid-Continent and Appalachia regions and the transportation of NGLs in the Mid-Continent. 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, 2011, 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, 2011, the Partnership had 53,617,183 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS.

On February 17, 2011, Atlas Energy, Inc. (AEI), a formerly publicly-traded company, completed an agreement and plan of merger with Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), pursuant to which, among other things, AEI became a wholly-owned subsidiary of Chevron (the Chevron Merger). At the time of the Chevron Merger, AEI owned a 64.3% ownership interest in ATLS common units, and 1,112,000 of the Partnership s common units, along with 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units. The Partnership s common units and 12% cumulative Class C preferred units held directly by AEI were acquired by Chevron as part of the Chevron Merger. AEI contributed ATLS s general partner, Atlas Energy GP, LLC (formerly known as Atlas Pipeline Holdings GP, LLC) to ATLS, so that Atlas Energy GP, LLC became ATLS wholly-owned subsidiary. In addition, AEI distributed to its stockholders all ATLS common units it held. On May 27, 2011, the Partnership redeemed the 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units held by Chevron (see Note 6).

The Partnership has evaluated all events subsequent to the balance sheet date through the filing date of this Form 10-K and has determined there are no subsequent events that require disclosures.

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-K from amounts previously presented as follows:

The Partnership has retrospectively adjusted its prior period consolidated financial statements to reclassify accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 10).

The Partnership has retrospectively adjusted its prior period consolidated financial statements to separately present derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

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.

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), which was sold on February 17, 2011; and its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which was acquired on May 11, 2011. 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 (loss) as equity income (loss) on its consolidated statements of operations.

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, 2011 and 2010, the Partnership reclassified balances related to outstanding checks of $26.2 million and $14.2 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, 2011 and 2010, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

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 are expensed as incurred. Major renewals and improvements that extend the useful lives of property 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 and processing systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering and processing 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.

Capitalized Interest

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 7.0%, 7.5% and 6.4% for the years ended December 31, 2011, 2010 and 2009, respectively. The amount of interest capitalized was $5.1 million, $0.8 million and $2.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Capital Leases

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. 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).

During the year ended December 31, 2009, the Partnership completed an evaluation of certain assets based on the current operating conditions and business plans for those assets, including idle and inactive pipelines and equipment. Based on the results of this review, the Partnership recognized an impairment charge of approximately $10.3 million for the year ended December 31, 2009, within other asset impairments on the Partnership s consolidated statements of operations. No impairment charges were recognized for the years ended December 31, 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, 2011 or 2010 because the settlement dates were indeterminable. Any cost incurred in the future to remove assets and restore sites will be expensed as incurred.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates. The Partnership records each derivative instrument in the balance sheet as either an asset or liability 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 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 will be reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affect earnings. The Partnership will reclassify the $4.4 million net loss in accumulated other comprehensive loss, within equity on the Partnership s consolidated balance sheets at December 31, 2011, to natural gas and liquids sales on the Partnership s consolidated statements of operations over the next twelve month period.

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 fair value methodology to value the assets and liabilities for its outstanding derivative contracts. 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.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at December 31, 2011 and 2010 (in thousands):

	December 31, 2011	December 31, 2010	Estimated Useful Lives In Years
Customer relationships:			
Gross carrying amount	$ 205,313	$ 205,313	7 10
Accumulated amortization	(102,037)	(78,934)	
Net carrying amount	$ 103,276	$ 126,379	

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 to determine if adjustments are required. 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. The weighted-average amortization period for customer relationships is 9.1 years. The Partnership recorded amortization expense on intangible assets of $23.1 million for each of the years ended December 31, 2011, 2010 and 2009. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2012 to 2013 $23.1 million per year; 2014 $19.5 million; 2015 to 2016 $14.5 million per year.

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. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for 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, 2011.

The Partnership files income tax returns 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 2008. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2011.

Share-Based Compensation

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

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholders interests. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% general partner interest and incentive distributions to be distributed for the quarter (see Note 8), 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 16), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award s vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. 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.

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,		
	2011	**2010**	**2009**
Continuing operations:			
Net income (loss)	$ 295,478	$ (40,717)	$ (21,434)
Income attributable to non-controlling interests	(6,200)	(4,738)	(3,176)
Preferred unit dividends	(389)	(780)	(900)
Net income (loss) attributable to common limited partners and the General Partner	288,889	(46,235)	(25,510)
General Partner s cash incentive distributions declared	1,666		
General Partner s ownership interest	5,774	(888)	(513)
Net income (loss) attributable to the General Partner s ownership interests	7,440	(888)	(513)
Net income (loss) attributable to common limited partners	281,449	(45,347)	(24,997)
Net income attributable to participating securities phantom units[(1)]	2,187		
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ 279,262	$ (45,347)	$ (24,997)
Discontinued operations:			
Net income (loss)	$ (81)	$ 321,155	$ 84,148
Net income (loss) attributable to the General Partner s ownership interests	(2)	6,134	1,691
Net income (loss) utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	$ (79)	$ 315,021	$ 82,457

(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 years ended December 31, 2010 and 2009, net loss attributable to common limited partners ownership interest is not allocated to approximately 300,000 and 82,000 phantom units, respectively, 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 16).

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,		
	2011	**2010**	**2009**
Weighted average number of common limited partner units basic	53,525	53,166	48,299
Add effect of participating securities phantom units[(1)]	419		
Add effect of dilutive option incentive awards[(2)]			
Add effect of dilutive unit warrants [(3)]			
Weighted average common limited partner units diluted	53,944	53,166	48,299

(1) For the years ended December 31, 2010 and 2009, approximately 300,000 and 82,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

(2) 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. There were no unit options outstanding for the year ended December 31, 2011.

(3) For the year ended December 31, 2009, 2,689,765 potential common limited partner units issuable upon exercise of the Partnership s warrants (see Note 5) were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive. There were no warrants outstanding for the years ended December 31, 2011 and 2010.

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. The Partnership maintains insurance, which may cover, in whole or in part, certain environmental expenditures. At December 31, 2011 and 2010, the Partnership had no material environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

During 2011, the Partnership realigned its reportable segments into two new segments. The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to the Partnership s 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. Gathering and

Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas. The Pipeline Transportation segment consists of the equity income generated by the newly acquired interest in WTLPG, which owns a 2,295 mile common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Pipeline revenues are primarily derived from transportation fees.

Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering, processing 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, 2011 and 2010 of $68.6 million and $57.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Recently Issued 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 IFRSs, 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. Early adoption is prohibited. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and 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. The amendments in this update require all nonowner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Early adoption is permitted. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and 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. These requirements are effective for interim and annual reporting periods beginning after January 1, 2013 and shall be applied retrospectively for any period presented that begins before the date of initial application. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2013. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

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. These amendments are being made to allow the FASB time to redeliberate whether to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income for all periods presented and to evaluate alternative presentation formats. All other requirements in ASU 2011-05 are not affected by Update ASU 2011-12. These requirements are effective for interim and annual reporting periods beginning after

December 15, 2011. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

NOTE 3   INVESTMENT IN JOINT VENTURES

Laurel Mountain

On May 31, 2009, the Partnership and subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams   ) completed the formation of Laurel Mountain, a joint venture, which owns and operates the Appalachia natural gas gathering system previously owned by the Partnership. Williams contributed cash of $100.0 million to the joint venture (of which the Partnership received approximately $87.8 million, net of working capital adjustments) and a note receivable of $25.5 million. The Partnership contributed the Appalachia natural gas gathering system and retained a 49% non-controlling ownership interest in Laurel Mountain. The Partnership is also entitled to preferred distribution rights relating to all payments on the note receivable. Williams obtained the remaining 51% ownership interest in Laurel Mountain.

Upon completion of the transaction, the Partnership recognized its 49% non-controlling ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheets at fair value. During the year ended December 31, 2009, the Partnership recognized a gain on the sale of $108.9 million, including $54.2 million associated with the revaluation of the Partnership   s investment in Laurel Mountain to fair value. The revaluation of the retained investment was determined based upon the value received for the 51% contributed to the Laurel Mountain joint venture. The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured credit facility (see Note 13).

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 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 therewith, AEI became a wholly-owned subsidiary of Chevron and divested its interests in ATLS (see Note 1), 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. The Partnership utilized the proceeds from the sale to repay its indebtedness (see Note 13) and for general company purposes.

The Partnership recognized its 49% non-controlling ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheets at fair value. 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 the $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 and made cash payments of $26.5 million during the year ended December 31, 2010, for capital contributions to Laurel Mountain. In December 2011, Williams made cash payment to the Partnership to settle the remaining $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. The Partnership recognizes its 20% interest in WTLPG as an investment in joint venture 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 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 tables summarize the components of the investment in joint ventures on the Partnership s consolidated balance sheets and the components of equity income on the Partnership s statements of operations (in thousands).

	December 31, 2011	December 31, 2010
Investment in Laurel Mountain	$	$ 153,358
Investment in WTLPG	86,879	
Investment in joint ventures	$ 86,879	$ 153,358

	Years Ended December 31,		
	2011	2010	2009
Equity income in Laurel Mountain	$ 462	$ 4,920	$ 4,043
Equity income in WTLPG	4,563		
Equity income in joint ventures	$ 5,025	$ 4,920	$ 4,043

NOTE 4 DISCONTINUED OPERATIONS

On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra) for net proceeds of $294.5 million in cash, net of working capital adjustments. The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured term loan and revolving credit facility (see Note 13). The Partnership accounted for the sale of the NOARK system assets as discontinued operations within its consolidated financial statements and recorded a gain of $51.1 million on the sale of the NOARK assets within income from discontinued operations on its consolidated statements of operations during the year ended December 31, 2009. The NOARK system was previously reported within the Partnership s Mid-Continent segment of 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 18).

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	2009
NOARK			
Total revenues	$	$	$ 21,274
Total costs and expenses			(9,857)
Earnings from discontinued operations			11,417
Gain on asset sales and other			51,078
Income from NOARK discontinued operations			62,495
Elk City			
Total revenues		129,908	167,543
Total costs and expenses		(120,855)	(148,383)
Earnings from discontinued operations		9,053	19,160
Gain (loss) on asset sales and other	(81)	312,102	2,493
Income (loss) from Elk City discontinued operations	(81)	321,155	21,653
Total income (loss) from discontinued operations	$ (81)	$ 321,155	$ 84,148

The Partnership s continuing operations include $18.0 million and $45.9 million within natural gas and liquids sales on the consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively, 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 5 COMMON UNIT EQUITY OFFERINGS

In August 2009, the Partnership sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. The Partnership also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in the Partnership. In addition, the Partnership issued warrants granting investors in its 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 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 13).

In January 2010, the Partnership executed amendments to the warrants originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 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 13) 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%.

NOTE 6 PREFERRED UNIT EQUITY OFFERINGS

Class A Preferred Units

In January 2009, the Partnership and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates amended certain terms of the 6.5% cumulative convertible preferred units (Class A Preferred Units) held by Sunlight Capital. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, and (b) required that the Partnership issue Sunlight Capital $15.0 million of its 8.125% senior unsecured notes due 2015 (see Note 13) to redeem 10,000 Class A Preferred Units. Management of the Partnership estimated that the fair value of the $15.0 million 8.125% senior unsecured notes issued to redeem the Class A Preferred Units was approximately $10.0 million at the date of redemption based upon the market price of the publicly-traded senior notes. As such, the Partnership recorded the redemption by recognizing a $10.0 million reduction of Class A Preferred equity within Equity, $15.0 million of additional long-term debt for the face value of the senior unsecured notes issued, and a $5.0 million discount on the issuance of the senior unsecured notes, which is presented as a reduction of long-term debt on the Partnership s consolidated balance sheets.

On April 1, 2009, the Partnership redeemed 10,000 of the Class A Preferred Units for cash at the liquidation value of $1,000 per unit, or $10.0 million, plus $0.3 million, representing the quarterly dividend on the 10,000 preferred units prior to the Partnership s redemption. On April 13, 2009, the Partnership converted 5,000 of the Class A Preferred Units into 1,465,653 Partnership common units reclassifying $5.0 million from Class A preferred limited partner equity to common limited partner equity within Equity. On May 5, 2009, the Partnership redeemed the remaining 5,000 Class A Preferred Units for cash at the liquidation value of $1,000 per unit, or $5.0 million, plus $0.2 million, representing the quarterly dividend on the 5,000 Class A Preferred Units prior to the Partnership s redemption. There are no longer any Class A Preferred Units outstanding.

The Partnership recognized $0.4 million of preferred dividend cost for the year ended December 31, 2009, for dividends paid to the Class A preferred units, 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 B Preferred Units

In December 2008 and March 2009, ATLS purchased 10,000 and 5,000, respectively, Class B Preferred Units (the Class B Preferred Units) for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a certificate of designation (the Class B Preferred Units Certificate of Designation) for net proceeds of $10.0 million and $5.0 million, respectively. The Class B Preferred Units received distributions of 12.0% per annum. Additionally, on March 30, 2009, the Partnership and ATLS agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units were not convertible into common units of the

Partnership. The cumulative sale of the Class B Preferred Units to ATLS was exempt from the registration requirements of the Securities Act of 1933.

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 longer any Class B Preferred Units outstanding. The Partnership recognized $2.9 million and $0.5 million of preferred dividend cost for the years ended December 31, 2010 and 2009, respectively, 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, the Class C Preferred Units were acquired by Chevron as part of the Chevron Merger (see Note 1). On May 27, 2011, the Partnership redeemed all 8,000 Class C Preferred Units outstanding 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 the Partnership s redemption. There are no longer any Class C Preferred Units outstanding. The Partnership recognized $0.4 million and $0.5 million of preferred dividend cost for the years ended December 31, 2011 and 2010, respectively, 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.

NOTE 7 INVESTMENT IN ATLAS PIPELINE HOLDINGS II, LLC

In June 2009, the Partnership purchased 15,000 12.0% cumulative preferred units (the preferred units) from a newly-formed subsidiary of ATLS, Atlas Pipeline Holdings II, LLC (AHD Sub), for cash consideration of $1,000 per unit, for an aggregate investment of $15.0 million.

The preferred units were to receive cash distributions of 12.0% per annum, to be paid quarterly. On November 15, 2010, AHD Sub exercised its option to redeem its 15,000 12.0% cumulative preferred units for cash at the liquidation value of $1,000 per unit, or $15.0 million plus $0.2 million accrued dividends. Concurrently, the Partnership redeemed its 15,000 units of Class B Preferred Units held by ATLS for cash at the liquidation value of $1,000 per unit, or $15.0 million plus $0.2 million accrued dividends (see Note 6).

The Partnership accounted for the preferred units as treasury units, with the investment reflected at cost as a reduction of equity within its consolidated balance sheets. The Partnership recognized $2.6 million of preferred dividend income for the year ended December 31, 2010, which is presented as net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations. There are no longer any preferred units outstanding.

NOTE 8 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. In connection with the Partnership s acquisition of control of the WestOK and WestTX systems, the General Partner, which holds all the incentive distribution rights in the Partnership, 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 from January 1, 2009 through December 31, 2011 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, 2008	February 13, 2009	$ 0.38	$ 17,463	$ 358
March 31, 2009	May 15, 2009	0.15	7,149	147
June 30, 2009	None	0.00		
September 30, 2009	None	0.00		
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

On January 26, 2012, the Partnership declared a cash distribution of $0.55 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2011. The $31.5 million distribution, including $2.0 million to the General Partner for its general partner interest and incentive distributions, was paid on February 14, 2012 to unitholders of record at the close of business on February 7, 2012.

NOTE 9 PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2011	December 31, 2010	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,615,015	$ 1,340,944	2 40
Rights of way	161,191	156,713	20 40
Buildings	8,047	8,047	40
Furniture and equipment	9,392	8,981	3 7
Other	14,029	12,659	3 10
	1,807,674	1,527,344	
Less accumulated depreciation	(239,846)	(186,342)	
	$ 1,567,828	$ 1,341,002	

The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 13), of $54.3 million, $51.8 million and $52.6 million for the years ended December 31, 2011, 2010 and 2009, respectively, on its consolidated statements of operations.

NOTE 10 OTHER ASSETS

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

	December 31, 2011	December 31, 2010
Deferred finance costs, net of accumulated amortization of $18,864 and $24,436 at December 31, 2011 and 2010, respectively	$ 20,750	$ 26,227
Security deposits	4,399	2,841
	$ 25,149	$ 29,068

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). During the years ended December 31, 2011, 2010 and 2009, the Partnership recorded $5.2 million, $4.4 million and $2.5 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. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was $4.5 million, $6.2 million and $5.5 million for the years ended December 31, 2011, 2010 and 2009, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2012 to 2014 $4.6 million per year; 2015 $4.3 million; 2016 $0.9 million per year.

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. It also previously entered into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as

the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. 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. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. As such, changes in fair value of derivatives are recognized immediately within derivative 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, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. The Partnership will reclassify the $4.4 million net loss in accumulated other comprehensive loss, within equity on the Partnership s consolidated balance sheets at December 31, 2011, to natural gas and liquids sales on the Partnership s consolidated statements of operations over the next twelve month period.

The portion of any gain or loss in accumulated other comprehensive loss related to originally forecasted transactions that are no longer expected to occur are removed from accumulated other comprehensive loss and recognized within the statements of operations. In September 2010, the Partnership sold its Elk City assets (see Note 4), and recognized a loss of $10.6 million within discontinued operations in the Partnership s statements of operations with a corresponding decrease in accumulated other comprehensive loss within equity on the Partnership s consolidated balance sheets, since the related originally forecasted transactions related to Elk City were no longer expected to occur.

Derivatives are recorded on the Partnership s consolidated balance sheets as assets or liabilities at fair value on the basis of its net exposure to each counterparty. Premium costs 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 loss, net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premium costs are reclassified to realized gain (loss) within derivative loss, net at the time the option expires or is exercised. The Partnership reflected net derivative assets on its consolidated balance sheet of $16.5 million at December 31, 2011 and net derivative liabilities on its consolidated balance sheet of $10.2 million at December 31, 2010.

The fair value of the Partnership s derivative instruments was included in its consolidated balance sheets as follows (in thousands):

	December 31, 2011	December 31, 2010
Current portion of derivative assets	$ 1,645	$
Long-term portion of derivative assets	14,814	
Current portion of derivative liabilities		(4,564)
Long-term portion of derivative liabilities		(5,608)
Net derivative assets/(liabilities)	$ 16,459	$ (10,172)

The following table summarizes the Partnership s gross fair values of commodity-based derivative instruments for the periods indicated (in thousands):

Balance Sheet Location	December 31, 2011	December 31, 2010
Asset Derivatives		
Current portion of derivative assets	$ 11,603	$
Long-term portion of derivative assets	17,011	
Current portion of derivative liabilities		2,624
Long-term portion of derivative liabilities		1,052
Total assets	28,614	3,676
Liability Derivatives		
Current portion of derivative assets	(9,958)	
Long-term portion of derivative assets	(2,197)	
Current portion of derivative liabilities		(7,188)
Long-term portion of derivative liabilities		(6,660)
Total liabilities	(12,155)	(13,848)
Total Derivatives	$ 16,459	$ (10,172)

The following table summarizes the Partnership s commodity derivatives as of December 31, 2011, none of which are designated for hedge accounting (dollars and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed Price Swaps				
2012	NGLs	38,052	$ 1.41	$ (1,027)
2013	NGLs	11,592	1.30	(706)
2012	Crude Oil	303	95.61	(982)
2013	Crude Oil	156	92.78	(514)
Total Fixed Price Swaps				(3,229)
Options				
Purchased Put Options				
2012	NGLs	54,054	1.56	7,209
2013	NGLs	38,556	1.94	11,070
2012	Crude Oil	180	106.42	2,317
2013	Crude Oil	282	100.10	4,557
Purchased Call Options(3)				
2012	Crude Oil	180	125.20	354
Sold Call Options(3)				
2012	Crude Oil	498	94.69	(5,819)
Total Options				19,688
Total Commodity Derivatives				$ 16,459

(1) Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.
(2) See Note 12 for discussion on fair value methodology.
(3) Calls purchased for 2012 represent offsetting positions for calls sold as part of a costless collar. These offsetting positions were entered into to limit the loss, which could be incurred if crude oil prices continued to rise.

During the years ended December 31, 2010 and 2009 the Partnership made net payments of $25.3 million and $5.0 million, respectively, 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 year ended December 31, 2011.

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, 2011	2010	2009
Loss Recognized in Accumulated Other Comprehensive Loss			
Contract Type			
Interest rate contracts[1]	$	$	$ (2,268)
	$	$	$ (2,268)

		2011	2010	2009
Loss Reclassified from Accumulated Other Comprehensive Loss into Income				
Contract Type	**Location**			
Interest rate contracts[1]	Interest expense	$	$ (2,242)	$ (11,754)
Commodity contracts[1]	Natural gas and liquids sales	(6,834)	(15,570)	(31,000)
Commodity contracts[1]	Discontinued operations		(20,154)	(15,268)
		$ (6,834)	$ (37,966)	$ (58,022)

	2011	2010	2009
Gain (Loss) Recognized in Income (Derivatives not designated as hedges)			
Location in consolidated statements of operations			
Natural gas and liquid sales:			
Commodity contract realized[1][2]	$	$	$ 273
Derivative loss, net:			
Interest rate contract realized[2][3]		(604)	(443)
Interest rate contract unrealized[3][4]		598	(598)
Commodity contract - realized[2][3]	(13,123)	(5,890)	27,648
Commodity contract - unrealized[3][4]	(7,329)	(49)	(62,422)
Derivative loss, net	(20,452)	(5,945)	(35,815)
Discontinued operations:			
Commodity contract - realized[1][2]			(396)
Commodity contract - realized[2][3]		(101)	(36,486)
Commodity contract - unrealized[3][4]		766	35,296
Discontinued operations		665	(1,586)
	$ (20,452)	$ (5,280)	$ (37,128)

(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) Dedesignated cash flow hedges and non-designated hedges.
(4) 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

The Partnership uses a fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 11). At December 31, 2011, all the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. 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 price for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations, and therefore are defined as Level 3. 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 following table represents the Partnership s derivative assets and liabilities recorded at fair value as of December 31, 2011 and 2010 (in thousands):

	Level 1	Level 2	Level 3	Total
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
December 31, 2010				
Assets				
Commodity swaps	$	$ 1,225	$ 124	$ 1,349
Commodity options		2,327		2,327
Total assets		3,552	124	3,676
Liabilities				
Commodity swaps		(1,461)	(1,914)	(3,375)
Commodity options		(10,473)		(10,473)
Total liabilities		(11,934)	(1,914)	(13,848)
Total derivatives	$	$ (8,382)	$ (1,790)	$ (10,172)

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, 2011 and 2010 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance December 31, 2009		$	43,470	$ 1,268	$ 1,268
New contracts[1]	57,246		8,820		
Cash settlements from unrealized gain (loss)[2][3]	(24,486)	1,634	(52,290)	7,246	8,880
Net change in unrealized gain (loss)[2]		(3,424)		(2,005)	(5,429)
Deferred option premium recognition[3]				(6,509)	(6,509)
Balance December 31, 2010	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

(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.

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 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. The estimated fair values of the Partnership s total debt at December 31, 2011 and 2010, which consists principally of borrowings under the revolving credit facility, the 8.125% Senior Notes and the 8.75% Senior Notes, were $537.3 million and $532.3 million, respectively, compared with the carrying amounts of $524.1 million and $566.0 million, respectively. The Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the revolving credit facility, which bears interest at a variable interest rate, approximates its estimated fair value.

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	December 31, 2011	December 31, 2010
Revolving credit facility	$ 142,000	$ 70,000
8.125% Senior notes due 2015		272,181
8.75% Senior notes due 2018	370,983	223,050
Capital lease obligations	11,157	743
Total debt	524,140	565,974
Less current maturities	(2,085)	(210)
Total long term debt	$ 522,055	$ 565,764

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

Years Ended December 31:	
2012	$ 2,085
2013	9,008
2014	64
2015	142,000
2016	
Thereafter	365,822
Total principal maturities	518,979
Unamortized premium	5,161
Total debt	$ 524,140

Cash payments for interest related to debt, net of capitalized interest, were $27.4 million, $88.8 million and $90.7 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Revolving Credit Facility

At December 31, 2011, the Partnership had a $450.0 million senior secured revolving credit facility with a syndicate of banks that matures in December 2015. 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, 2011, was 3.1%. 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, 2011. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At December 31, 2011, the Partnership had $307.9 million of remaining committed capacity under its revolving credit facility.

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 WestOK and WestTX joint ventures; 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, 2011, the Partnership was in compliance with all covenants under the credit facility.

In July 2011, the revolving credit facility was increased from $350.0 million to $450.0 million. In September 2010, a $425.8 million term loan, scheduled to mature in July 2014, was paid in full with proceeds received from the Elk City asset sale (see Note 4).

8.75% Senior Notes

At December 31, 2011, the Partnership had $371.0 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes), including a net $5.2 million unamortized premium. 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 8.75% 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 8.75% Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its revolving credit facility.

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 sale of the Partnership s 49% non-controlling interest in Laurel Mountain on February 17, 2011 constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, the Partnership offered to purchase any and all of the 8.75% Senior Notes. For the year ended December 31, 2011, the Partnership recorded a loss of $0.2 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the write off of deferred financing costs for the 8.75% Senior Notes.

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

The 8.75% Senior Notes sold in private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required the Partnership to file a registration statement with the SEC to exchange the privately placed notes for registered notes. The Partnership filed a registration statement with the SEC in satisfaction of the requirements of the registration rights agreement on December 12, 2011, and the registration statement was declared effective on January 13, 2012. The Partnership currently anticipates completing the exchange offer on March 5, 2012.

The indenture governing the 8.75% Senior Notes contains 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, 2011.

8.125% Senior Notes

In January 2009, the Partnership issued Sunlight Capital $15.0 million of its 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) to redeem 10,000 Class A Preferred Units (see Note 6). Management of the Partnership estimated that the fair value of the $15.0 million 8.125% Senior Notes issued was approximately $10.0 million at the date of issuance based upon the market price of the publicly-traded Senior Notes. As such, the Partnership recognized a $5.0 million discount on the issuance of the Senior Notes, which was presented as a reduction of long-term debt on its consolidated balance sheets. The discount recognized upon issuance of the Senior Notes was amortized to interest expense within the Partnership s consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method until the 8.125% Senior Notes were redeemed.

In November 2010, the Partnership paid $1.3 million to the holders of the 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. 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 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. There were no 8.125% Senior Notes outstanding at December 31, 2011.

Capital Leases

On July 15, 2011, the Partnership amended an operating lease for eight compressors to include 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. During the year ended December 31, 2010, the Partnership entered into capital lease arrangements having obligations of $0.9 million at inception, which were recorded within property, plant and equipment with an offsetting liability recorded within long term debt on the Partnership s consolidated balance sheets.

The following is a summary of the leased property under capital leases, which are included within property, plant and equipment (see Note 9) (in thousands):

	December 31, 2011	December 31, 2010
Pipelines, processing and compression facilities	$ 12,507	$ 1,139
Less accumulated depreciation	(199)	(47)
	$ 12,308	$ 1,092

Amortization expense for leased properties was $152 thousand and $47 thousand for years ended December 31, 2011 and 2010, respectively, which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 9). There was no amortization expense for leased properties for the year ended December 31, 2009.

As of December 31, 2011, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2012	$ 2,685
2013	9,376
2014	64
2015	
2016	
Thereafter	
Total minimum lease payments	12,125
Less amounts representing interest	(968)
Present value of minimum lease payments	11,157
Less current portion of capital lease obligations	(2,085)
Long-term capital lease obligations	$ 9,072

NOTE 14 COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space that expire at various dates. Certain operating leases provide the Partnership with the option to renew for additional periods. Where operating leases contain escalation clauses, rent abatements, and/or concessions, the Partnership applies them in the determination of straight-line rent expense over the lease term. Leasehold improvements are amortized over the shorter of the lease term or asset life, which may include renewal periods where the renewal is reasonably assured, and is included in the determination of straight-line rent expense. Total rental expense for the years ended December 31, 2011, 2010 and 2009 was $5.5 million, $6.4 million and $6.8 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2011 is as follows (in thousands):

Years Ended December 31:	
2012	$ 1,580
2013	511
2014	269
2015	214
2016	108
Thereafter	
	$ 2,682

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. During the years ended December 31, 2011, 2010 and 2009, the Partnership paid $10.3 million, $9.5 million and $2.4 million, respectively, for transportation fees related to these contracts. The future fixed and determinable portion of the obligations as of December 31, 2011 was as follows: 2012 to 2013 - $8.2 million per year; 2014 - $6.1 million.

The Partnership had committed approximately $73.2 million for the purchase of property, plant and equipment at December 31, 2011.

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.

As previously reported, on February 26, 2010, the Partnership received notice from Williams, its former joint venture partner in Laurel Mountain, alleging that certain title defects existed with respect to the real property contributed by the Partnership to Laurel Mountain; and in August 2010, Williams asserted additional indemnity claims under the Formation and Exchange Agreement with Williams totaling approximately $19.8 million. Based on the Partnership s analysis an accrual was established with respect to the portion of Williams claims that it deemed probable, which was less than 51% of the amounts asserted by Williams. In December 2011, the Partnership resolved the claims with Williams for an amount approximately equal to the Partnership s accrual.

NOTE 15 CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas, NGLs and condensate under contract to various purchasers in the normal course of business, within the Gathering and Processing segment (see Note 18). For the year ended December 31, 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. For the year ended December 31, 2009, the Partnership had two customers that individually accounted for approximately 56% and 16%, 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 56% and 15%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2011, and two customers that individually accounted for approximately 55% and 17%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2010.

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, 2011, the Partnership and its subsidiaries had $3.1 million in deposits at banks, of which $3.0 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 16 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. Except for phantom units awarded to non-employee managing board members of the General Partner and within the guidelines proscribed in each long term incentive plan, a committee (the LTIP 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 LTIP Committee shall determine how the exercise price may be paid by the grantee. The LTIP 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 LTIP Committee. Under the LTIPs, the LTIP Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At December 31, 2011, the Partnership had 394,489 phantom units outstanding under the Partnership s LTIPs, with 2,364,279 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, 2011, 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 may automatically vest upon a change of control, as defined in the LTIPs. At December 31, 2011, there were 180,748 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, 2011 and 2010, the Partnership purchased and retired 28,878 common units and 20,442 common units, respectively, to cover employee-related taxes, for a cost of $1.0 million and $0.2 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 1) 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, 2011 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were $0.8 million, $0.2 million and $0.1 million during the years ended December 31, 2011, 2010 and 2009, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

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

	Years Ended December 31,					
	2011		2010		2009	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	490,886	$ 11.75	52,233	$ 39.72	126,565	$ 44.22
Granted	178,318	33.47	575,112	10.49	2,000	4.75
Matured(2)(3)	(233,465)	11.34	(126,584)	17.11	(58,257)	45.68
Forfeited	(41,250)	13.49	(9,875)	17.39	(18,075)	48.17
Outstanding, end of period(4)(5)	394,489	$ 21.63	490,886	$ 11.75	52,233	$ 39.72
Non-cash compensation expense recognized (in thousands)(6)		$ 3,271		$ 3,480		$ 694

(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, 2011, 2010 and 2009 were $7.4 million and $1.5 million and $0.3 million, respectively.

(3) There were 414 matured phantom units, which were settled for $14 thousand cash during the year ended December 31, 2011. No phantom units were cash settled during the years ended December 31, 2010 and 2009.

(4) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2011 and 2010 was $14.7 million and $12.1 million, respectively.

(5) There were 14,675 and 8,010 outstanding phantom unit awards at December 31, 2011 and 2010, 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, 2011, the Partnership had approximately $5.3 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

Partnership Unit Options. At December 31, 2011, 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 1) and 50,000 outstanding unit options held by the CEO automatically vested. As of December 31, 2011, all unit options had been exercised.

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

	Years Ended December 31,					
	2011		2010		2009	
	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					100,000	6.24
Exercised(1)	(75,000)	6.24	(25,000)	6.24		
Outstanding, end of period(2)		$	75,000	$ 6.24	100,000	$ 6.24
Weighted average fair value of unit options per unit granted during the period		$		$	100,000	$ 0.14
Non-cash compensation expense recognized (in thousands)(3)		$ 3		$ 4		$ 7

(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.

The Partnership used the Black-Scholes option pricing model to estimate the weighted average fair value of options granted. The following weighted average assumptions were used for the period indicated:

	Year Ended December 31, 2009
Expected dividend yield	11.0%
Expected stock price volatility	20.0%
Risk-free interest rate	2.2%
Expected term (in years)	6.3

Employee Incentive Compensation Plan and Agreement

In June 2009, Atlas Pipeline Mid-Continent LLC, a wholly-owned subsidiary of the Partnership adopted 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 may be awarded to Participants at the discretion of the committee. During 2009, the committee granted 375,000 Bonus Units. 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. Vesting will terminate upon termination of employment with cause. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 Bonus Units agreed to exchange their Bonus Units for phantom units, effective as of June 1, 2010.

At December 31, 2011, the Partnership had 25,500 outstanding Bonus Units, which will all vest within the following twelve months. The Partnership recognizes 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 expense of $0.9 million and $1.2 million during the years ended December 31, 2011 and 2009, respectively, and a credit of $0.2 million during the year ended December 31, 2010, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had $0.8 million at both December 31, 2011 and 2010 included within accrued liabilities on its consolidated balance sheets with regard to these awards, which represents their fair value as of those dates.

NOTE 17 RELATED PARTY TRANSACTIONS

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

The partnership agreement provides that the General Partner will determine the costs and expenses allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. These costs and expenses are limited to $1.8 million for the twelve months following the closing of the Chevron Merger (see Note 1). The Partnership reimbursed the General Partner and its affiliates $1.8 million, $1.5 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, 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, 2011, 2010 and 2009. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

On February 17, 2011, the Partnership completed the sale of its 49% interest in Laurel Mountain to Atlas Energy Resources for $409.5 million, including closing adjustments and net of expenses (See Note 3).

NOTE 18 SEGMENT INFORMATION

On February 17, 2011, the Partnership sold its 49% interest in Laurel Mountain, which was reported as part of the Partnership s previous Appalachia segment (see Note 3). On May 11, 2011, the Partnership acquired a 20% interest in WTLPG (see Note 3). As a result of these two transactions, the Partnership realigned its reportable segments into two new segments: Gathering and Processing; and Pipeline Transportation (Pipeline). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to the Partnership s 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Pipeline segment consists of the equity income generated by the newly acquired interest in WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Pipeline revenues are primarily derived from transportation fees.

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

	Gathering and Processing	Pipeline	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[2]:				
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

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
Year Ended December 31, 2009[(2)]:				
Revenue:				
Revenues third party[(1)]	$ 721,611	$	$ (66,542)	$ 655,069
Revenues affiliates	17,536			17,536
Total revenues	739,147		(66,542)	672,605
Costs and Expenses:				
Operating costs and expenses	579,953			579,953
General and administrative[(1)]			37,280	37,280
Depreciation and amortization	75,684			75,684
Goodwill and other asset impairment loss	10,325			10,325
Interest expense[(1)]			101,309	101,309
Total costs and expenses	665,962		138,589	804,551
Equity income	4,043			4,043
Gain on asset sales and other	108,947			108,947
Loss on early extinguishment of debt			(2,478)	(2,478)
Net income (loss) from continuing operation	186,175		(207,609)	(21,434)
Income from discontinued operations			84,148	84,148
Net income (loss)	$ 186,175	$	$ (123,461)	$ 62,714

	Years Ended December 31,		
	2011	2010[(2)]	2009[(2)]
Capital Expenditures:			
Gathering and Processing	$ 245,426	$ 46,636	$ 110,274
Pipeline			
	$ 245,426	$ 46,636	$ 110,274

Balance Sheet	December 31, 2011	December 31, 2010[(2)]
Investment in joint ventures:		
Gathering and Processing	$	$ 153,358
Pipeline	86,879	
	$ 86,879	$ 153,358
Total assets:		
Gathering and Processing	$ 1,806,550	$ 1,738,493
Pipeline	87,053	
Corporate other	37,209	26,355
	$ 1,930,812	$ 1,764,848

(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) Adjusted to reflect the realignment of the segments due to the sale of Laurel Mountain and the acquisition of WTLPG (see Note 3) and to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

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, 2011	2010	2009
Natural gas and liquids sales:			
Natural gas	$ 400,991	$ 299,461	$ 257,297
NGLs	795,122	548,308	351,410
Condensate	72,037	41,933	23,626
Other	45	346	3,898
Total	$ 1,268,195	$ 890,048	$ 636,231

NOTE 19 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s 8.75% 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, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 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. Under the terms of the 8.75% Senior Notes and the revolving credit facility, WestOK LLC and WestTX LLC 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, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009. 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):

Balance Sheets

December 31, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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
Investment in joint ventures		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

December 31, 2010	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 164	$	$	$ 164
Accounts receivable affiliates	1,329,448			(1,329,448)	
Other current assets	202	25,488	89,187		114,877
Total current assets	1,329,650	25,652	89,187	(1,329,448)	115,041
Property, plant and equipment, net		243,092	1,097,910		1,341,002
Intangible assets, net			126,379		126,379
Investment in joint ventures		153,358			153,358
Notes receivable			1,852,928	(1,852,928)	
Equity investments	252,725	(633,455)		380,730	
Other assets, net	26,605	1,775	688		29,068
Total assets	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848
Liabilities and Equity					
Accounts payable affiliates	$	$ 1,173,729	$ 167,999	$ (1,329,448)	$ 12,280
Current portion of derivative liability		4,564			4,564
Other current liabilities	2,102	47,162	85,498		134,762
Total current liabilities	2,102	1,225,455	253,497	(1,329,448)	151,606
Long-term derivative liability		5,608			5,608
Long-term debt, less current portion	565,231		533		565,764
Other long-term liability		223			223
Equity	1,041,647	(1,440,864)	2,913,062	(1,472,198)	1,041,647

Total liabilities and equity	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848

Statements of Operations	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2011					
Total revenues	$	$ 238,047	$ 1,064,687	$	$ 1,302,734
Total costs and expenses	(28,682)	(292,818)	(927,479)		(1,248,979)
Equity income	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 from continuing operations	293,099	340,981	137,208	(475,810)	295,478
Income from discontinued operations		(81)			(81)
Net income	$ 293,099	$ 340,900	$ 137,208	$ (475,810)	$ 295,397
Year Ended December 31, 2010(1)					
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	$ 284,852	$ 323,419	$ 112,858	$ (440,691)	$ 280,438
Year Ended December 31, 2009(1)					
Total revenues	$	$ 71,639	$ 600,966	$	$ 672,605
Total costs and expenses	(103,629)	(192,517)	(508,405)		(804,551)
Equity income	164,801	98,236		(258,994)	4,043
Gain on asset sales and other		108,947			108,947
Loss on early extinguishment of debt		(2,478)			(2,478)
Income (loss) from continuing operations	61,172	83,827	92,561	(258,994)	(21,434)
Income from discontinued operations		84,148			84,148
Net income	$ 61,172	$ 167,975	$ 92,561	$ (258,994)	$ 62,714

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2011					
Net cash provided by (used in):					
Total 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
Total 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
Year Ended December 31, 2009					
Net cash provided by (used in):					
Continuing operating activities	$ 153,969	$ (85,466)	$ 205,745	$ (260,537)	$ 13,711
Discontinued operating activities		42,142			42,142
Total operating activities	153,969	(43,324)	205,745	(260,537)	55,853
Continuing investing activities	141,661	(7,857)	(60,108)	(97,960)	(24,264)
Discontinued investing activities		265,387			265,387
Total investing activities	141,661	257,530	(60,108)	(97,960)	241,123
Total financing activities	(295,637)	(214,623)	(145,637)	358,497	(297,400)
Net change in cash and cash equivalents	(7)	(417)			(424)
Cash and cash equivalents, beginning of period	7	1,438			1,445
Cash and cash equivalents, end of period	$	$ 1,021	$	$	$ 1,021

(1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

NOTE 20 QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter[(1)]	Third Quarter[(2)]	Second Quarter[(3)]	First Quarter[(4)]
	(in thousands, except per unit data)			
Year ended December 31, 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	$ (0.15)	$ 0.87	$ 0.13	$ 4.37
Net income (loss) attributable to common limited partners per unit 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 3).
(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 3).
(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.

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2010(5):				
Revenue	$ 253,090	$ 226,118	$ 216,227	$ 240,153
Costs and expenses	(254,176)	(241,003)	(224,440)	(246,518)
Equity income in joint venture	783	1,787	888	1,462
Loss on sale of asset and other	(10,729)			
Loss on early extinguishment of debt		(4,359)		
Loss from continuing operations	(11,032)	(17,457)	(7,325)	(4,903)
Income from discontinued operations	471	305,927	7,976	6,781
Net income (loss)	(10,561)	288,470	651	1,878
Income attributable to non-controlling interests	(1,400)	(1,076)	(945)	(1,317)
Preferred unit dividends	(540)	(240)		
Net income (loss) attributable to common limited partners and the General Partner	$ (12,501)	$ 287,154	$ (294)	$ 561
Net income (loss) attributable to common limited partners per unit basic:				
Loss from continuing operations attributable to common limited partners	$ (0.24)	$ (0.34)	$ (0.15)	$ (0.12)
Income from discontinued operations attributable to common limited partners	0.01	5.63	0.14	0.13
Net income (loss) attributable to common limited partners	$ (0.23)	$ 5.29	$ (0.01)	$ 0.01
Net income (loss) attributable to common limited partners per unit diluted:(6)(7)				
Loss from continuing operations attributable to common limited partners	$ (0.24)	$ (0.34)	$ (0.15)	$ (0.12)
Income from discontinued operations attributable to common limited partners	0.01	5.63	0.14	0.13
Net income (loss) attributable to common limited partners	$ (0.23)	$ 5.29	$ (0.01)	$ 0.01

(1) Net income includes a $6.0 million non-cash derivative loss and a $10.7 million loss related to the sale of Laurel Mountain (see Note 3).

(2) Net income includes an $18.6 million non-cash derivative loss and a $311.5 million gain on the sale of Elk City (see Note 4).

(3) Net income includes a $19.1 million non-cash derivative gain and a $20.4 million net cash derivative expense from the early termination of certain derivative instruments.

(4) Net income includes a $20.6 million non-cash derivative gain and a $13.4 million cash derivative expense from the early termination of certain derivative instruments.

(5) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

(6) For the first, second, third and fourth quarters of the year ended December 31, 2010, approximately 51,000, 113,000, 532,000 and 499,000 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.

(7) For the first, second, third and fourth quarters of the year ended December 31, 2010, approximately 100,000, 100,000, 100,000, and 75,000 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.

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. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2011, 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.

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, 2011. 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, 2011, which is included herein.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited Atlas Pipeline Partners, L.P. s (a Delaware limited partnership) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlas Pipeline Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Atlas Pipeline Partners, L.P. s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atlas Pipeline Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 balance sheets of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2011 and 2010 and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2011, and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 24, 2012

ITEM 9B. OTHER INFORMATION

None.

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 and audit 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. 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.

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, Atlas Energy, L.P. (ATLS) personnel manage and operate our business. 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.

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	73	Chairman of the Managing Board	1999
Jonathan Z. Cohen	41	Vice Chairman of the Managing Board	1999
Eugene N. Dubay	63	Chief Executive Officer, President and Managing Board Member	2008
Robert W. Karlovich, III	34	Chief Financial Officer	2009
Gerald R. Shrader	52	Chief Legal Officer and Secretary	2009
Tony C. Banks	57	Managing Board Member	1999
Curtis D. Clifford	69	Managing Board Member	2004
Gayle P. W. Jackson	65	Managing Board Member	2011
Martin Rudolph	65	Managing Board Member	2005
Michael L. Staines	62	Managing Board Member	1999

Edward E. Cohen has been the 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 the consummation of the Chevron Merger in February 2011, 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 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 still serves on its board; a director of TRM Corporation (a publicly traded consumer services company) from 1998 to July 2007; 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 since the late 1970s. Among the reasons for his appointment as a director, Mr. Cohen brings to the board the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country.

Jonathan Z. Cohen has been Vice Chairman of the managing board of our General Partner since our formation in 1999. Mr. Cohen has been the Chairman of the Board of Atlas Energy, GP, the general partner of ATLS, since February 2011 and before that he served as its 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 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. since its formation in 2005 and was a trustee and secretary of RAIT Financial Trust (a publicly-traded real estate investment trust) from 1997, and its Vice Chairman from 2003, until December 2006. Mr. Cohen is a son of Edward E. Cohen. Among the reasons for his appointment as a director, Mr. Cohen s financial, business and energy experience add strategic vision to our board to assist with our growth and development.

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. This combined experience and approach 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 March 2011. Before that, he was the Controller of Atlas Pipeline Mid-Continent LLC since September 2006. Mr. Karlovich was the Controller for Syntroleum Corporation, a publicly-traded energy company, from April 2005 until September 2006, and Accounting Manager from February 2004. Mr. Karlovich also worked as a public accountant with Arthur Andersen LLP and Grant Thornton LLP where he served numerous public clients and energy companies. Mr. Karlovich is a certified public accountant.

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

Tony C. Banks has been Vice President of Competitive Market Policies since February 2011 of FirstEnergy Solutions Corp., a subsidiary of FirstEnergy Corporation, a public utility, and before that, he served as Vice President of Product and Market Development from October 2009 to February 2011. From March 2007 to October 2009, Mr. Banks served as Vice President of Business Development, Performance & Management for FirstEnergy Corporation. From December 2005 to February 2007, Mr. Banks was Vice President of Business Development for FirstEnergy Corporation. 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. He was Chief Executive Officer and President of AEI from 1998 through 2000 and served on the board of directors of TRM Corporation, a provider of ATM services, from October 2006 to April 2008. In Mr. Banks role at AEI, he gained experience in natural gas exploration and production. Prior to that time, Mr. Banks was engaged primarily in the natural gas distribution business. Currently, Mr. Banks is engaged primarily with electricity generation, pricing and marketing including involvement with renewable energy standards and compliance with certain emission requirements for electricity generators. Among the reasons for Mr. Banks appointment as a director, Mr. Banks supplements the knowledge of our other board members with respect to natural gas production and the energy markets, including markets for natural gas.

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 of Amity Manor, Inc. 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 45 years experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and utility rates. Among the reasons for his appointment as a director, 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 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, and 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. Dr. Jackson brings to the board her extensive experience in the energy industry, including her previous service as a director of our General Partner as well as AEI. Dr. Jackson also has a strong background in finance.

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. At McGladrey & Pullen LLP, Mr. Rudolph 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. Among the reasons for his appointment as a director, Mr. Rudolph s 40 years experience as an independent certified public accountant has been critical in developing our internal audit regime and is needed to further guide that program.

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. This knowledge and experience served as a basis for Mr. Staines appointment as a director. With this background, Mr. Staines advice can help guide our continued development.

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, our managing board of our General Partner determined that each of the managing board members should, as of the date hereof, serve on the managing board of our General Partner.

Edward E. Cohen serves as the 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 role of chairman of the managing board of our General Partner 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.

Risk Oversight

We administer our risk oversight function through our risk oversight committee, which was appointed by the managing board of our General Partner, to assist with its oversight duties for our risk management. The members of our risk oversight committee are Mr. Banks, Mr. Rudolph and Mr. Dubay, with Mr. Banks acting as the chairman. Our risk oversight committee reports both to the audit committee and 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 risk oversight committee provides oversight for a management-level risk management committee comprised of members of senior management that 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 risk oversight committee and our CEO. 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 for those persons, 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 2011, except that Mr. Dubay filed one late Form 5 in 2011 to report two gift transactions that took place in 2010; and Dr. Jackson filed one late Form 5 in 2012 to report three small exempt acquisitions that took place in 2011.

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 business time spent by those employees and officers on our business. These costs and expenses are limited to $1.8 million for the twelve months following the sale of our 49% interest in Laurel Mountain to Atlas Energy Resources on February 17, 2011, excluding salaries and expenses of officers and employees whose primary responsibility is our management and operation. We reimbursed our General Partner and its affiliates $1.8 million for compensation and benefits during 2011.

Information Concerning the Audit Committee

The managing board of our General Partner has a standing audit committee. All the members of the audit committee are independent directors as defined by NYSE rules. The members of the audit committee are Mr. Rudolph, Mr. Clifford, Mr. Banks and Dr. Jackson, with Mr. Rudolph acting as the chairman. 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

Neither we nor the managing board of our General Partner had a compensation committee for the year ended December 31, 2011. Compensation of the personnel of ATLS and its affiliates who provide us with services is set by ATLS and such affiliates. The independent members of the managing board of our General Partner, however, do review the allocation of the salaries of such personnel for purposes of reimbursement, discussed in Reimbursement of Expenses of our General Partner and Its Affiliates, above and in Item 11, Executive Compensation.

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. None of the other independent managing board members is an employee or former employee of ours or of our General Partner. 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 Audit Committee Charter

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 a charter for the audit committee. We will make a printed copy of our code of ethics, our Partnership Governance Guidelines and our audit committee charter 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 audit committee charter 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, 2011, 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. Atlas Energy, Inc. (AEI) for periods before February 17, 2011 and Atlas Energy, LP (ATLS), since then, allocated the compensation of our executive officers between activities on behalf of us and activities on behalf of themselves and their other affiliates based upon an estimate of the time spent by such persons on activities for us and for them and their affiliates. Because Messrs. Dubay, Kalamaras, Karlovich and Shrader devoted all their time to us, all their compensation costs were allocated to us. We reimbursed AEI and ATLS for the compensation allocated to us. Because ATLS employed our NEOs, effective February 2011, its compensation committee, comprised solely of independent directors, was responsible for formulating and presenting recommendations to its board of directors with respect to the compensation of our NEOs. The ATLS compensation committee was also responsible for administering our employee benefit plans, including our incentive plans.

Compensation Objectives

The ATLS 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 paid, if at all, based on individual and company accomplishment. Accounting and cost implications of compensation programs are considered in program design; however, the essential consideration is that a program is consistent with our business needs.

Compensation Methodology

The ATLS compensation committee generally makes recommendations to the ATLS board on compensation amounts shortly after the close of its (and our) fiscal year. In the case of base salaries, it recommends the amounts to be paid for the new fiscal year. In the case of annual bonus and long-term incentive compensation, the committee recommends the amount of awards based on the then concluded fiscal year. ATLS and we typically pay cash awards in February, although the ATLS compensation committee has the discretion to recommend salary adjustments and the issuance of equity awards at other times during the fiscal year. In addition, some of our NEOs also receive stock-based awards from ATLS.

Each year, the Chairman of our General Partner, who also serves as the CEO and President of ATLS general partner, provides the ATLS compensation committee with key elements of ATLS and our NEOs performance during the year. The Chairman makes recommendations to the ATLS compensation committee regarding the salary, bonus, and incentive compensation components of each NEO s total compensation. The Chairman, at the ATLS compensation committee s request, may attend compensation committee meetings solely to provide insight into ATLS and our company s performance, as well as the performance of other comparable companies in the same industry.

Role of Compensation Consultant

Following the completion of AEI s agreement and plan of merger with Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), pursuant to which, among other things, AEI became a wholly-owned subsidiary of Chevron (the Chevron Merger) in February 2011, the ATLS compensation committee engaged Mercer (US) Inc., an independent compensation consulting firm, to provide market data for equity awards to be made to its NEOs. As ATLS was essentially reconstituted as a result of the acquisition of AEI s partnership management business and certain E&P assets, the ATLS compensation committee intended the awards to represent multi-year long-term incentive grants competitive with the 75th percentile of the market. In order to assist the ATLS compensation committee in assessing the competitiveness of proposed awards, Mercer provided market data for long-term incentive grants to the 75th percentile from its 2010 oil and gas survey of data from 111 organizations. In addition, Mercer advised the ATLS compensation committee with respect to current employment agreement practices generally.

Elements of our Compensation Program

Our executive officer compensation package includes a combination of annual cash and long-term incentive compensation. Annual cash compensation is comprised of an allocation of base salary plus cash bonus awarded by ATLS. 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 the success of ATLS and us. Base salaries are not intended to compensate individuals for extraordinary performance or for above average company performance.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the NEO s compensation to ATLS annual performance and/or that of one of ATLS subsidiaries or divisions for which the officer is responsible. Generally, the higher the level of responsibility of the executive within ATLS the greater is the incentive component of that executive s target total cash compensation. The ATLS compensation committee may recommend awards of performance-based bonuses and discretionary bonuses.

Performance-Based Bonuses In April 2011, the ATLS compensation committee adopted an Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, to award bonuses for achievement of predetermined, objective performance measures through the end of 2011. Awards under the Senior Executive Plan could be paid in cash or in a combination of cash and equity. Under the Senior Executive Plan, the maximum award payable to an individual was $15,000,000.

At the time the ATLS compensation committee adopted the Senior Executive Plan, it approved 2011 target bonus awards to be paid from a bonus pool. The bonus pool was equal to 18.3% of ATLS distributable cash flow unless the distributable cash flow included any capital transaction gains in excess of $50 million, in which case only 10% of that excess would be included in the bonus pool. If the distributable cash flow did not equal at least 80% of the 2011 budgeted distributable cash flow of $84,498,000, no bonuses would be paid. 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 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 its basis in the subsidiary.

The maximum award payable, expressed as a percentage of ATLS estimated 2011 distributable cash flow, for each participant was as follows: Edward E. Cohen, 6.14%; Jonathan Z. Cohen, 4.37%; and Eugene Dubay, 2.60%. The other NEOs do not participate in the Senior Executive Plan. Pursuant to the terms of the Senior Executive Plan, the ATLS compensation committee had the discretion to recommend reductions, but not increases, in awards under the Senior Executive Plan.

Discretionary Bonuses Discretionary bonuses may be awarded to recognize individual and group performance.

Long-Term Incentives

The ATLS compensation committee believes our long-term success depends upon aligning our executives and unitholders interests. To support this objective, ATLS provides 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 ATLS compensation committee recommends grants of equity awards in the form of options and/or phantom units. Other than the unit options that were granted to Mr. Dubay in connection with the execution of his 2009 employment agreement, only phantom units have been granted under our Plans through December 31, 2011. Except for phantom units received in exchange for Bonus Units under the Atlas Pipeline Mid-Continent Plan (APLMC Plan), which vest over three years, the unit options and phantom units vest over four years.

Grants under Other Plans: As described above, our NEOs were eligible to receive stock-based awards under the ATLS Plans. In addition, we anticipate that some of our NEOs will be eligible to receive awards under the long-term incentive plan to be adopted by Atlas Resource Partners, L.P., ATLS newly formed subsidiary.

Post-Termination Compensation

Our NEOs received substantial cash amounts from Chevron in connection with the Chevron Merger, both as a result of the termination payments due under their employment agreements with AEI, which are described under Employment Agreements and Potential Payments Upon Termination or Change of Control, and their equity holdings in AEI. The ATLS compensation committee believed that the amounts thus realized left some of our NEOs without adequate financial incentives to continue employment with ATLS, which the ATLS committee did not believe was in ATLS interest as it moved forward with significant new operations. In order to encourage these executives to remain with ATLS on a long-term basis, it made certain long-term incentive grants, which are described under Long-Term Incentives, and 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. See Employment Agreements and Potential Payments Upon Termination or Change of Control. Good reason is defined under the agreements as:

- a material reduction in the executive s base salary;
- a demotion from the position held by the executive at the time the agreement was entered into;
- a material reduction in the executive s duties, it being deemed such a material reduction if ATLS ceases to be a public company unless, ATLS becomes a subsidiary of a public company and, in the case of Mr. E. Cohen s agreement, he becomes the chief executive officer of the public parent, or, in the case of Mr. J. Cohen s agreement, he becomes an executive of the public parent with responsibilities substantially equivalent to his position, or, in the case Mr. Dubay s agreement, ATLS CEO or chairman of its board are not, immediately following the transaction in which it ceases to be a public company, ATLS CEO or the CEO of the acquiring entity;
- the executive is required to relocate to a location more than 35 miles from his previous location;
- in the case of Messrs. E. and J. Cohen s agreements, he ceases to be elected to ATLS board; and;
- any material breach of the agreement.

The ATLS compensation committee s rationale behind the design of the provisions of these agreements for termination by the executive for good reason is as follows:

- Determination of Triggering Events The ATLS compensation committee elected not to include a change of control of ATLS as a good reason triggering event and instead limited the triggering events to those (including after a change of control of ATLS) where his position with ATLS changes substantially and is essentially an involuntary termination.

Benefit Multiple The ATLS compensation committee determined the benefit multiple, that is, the cash severance amount based on each executive s salary and bonus, after consideration of comparable market practices provided to the committee by Mercer.

Perquisites

We provide limited perquisites to our NEOs at the discretion of the ATLS compensation committee. In 2011, these benefits were limited to providing cars to some NEOs and reimbursement of relocation expenses and club membership dues.

Determination of 2011 Compensation Amounts

Base Salary

In February 2011, the ATLS compensation committee approved the base salaries for our NEOs as follows: Mr. Dubay $500,000, Mr. Karlovich $200,000, Mr. Kalamaras $295,000 and Mr. Shrader $290,000. These amounts represented a 0%, 11.5%, 7%, and 5% increase from the 2010 base salaries for each of Messrs. Dubay, Karlovich, Kalamaras and Shrader, respectively.

In February 2012, the ATLS compensation committee approved the base salaries for our NEOs as follows: Mr. Dubay $500,000, Mr. Karlovich $286,000 and Mr. Shrader $301,600. These amounts represent a 0%, 4% and 4% increase from the 2011 year-end base salaries for Messrs. Dubay, Karlovich and Shrader, respectively.

Annual and Transaction Incentives

The ATLS compensation committee was attentive to ATLS unique circumstances after the Chevron Merger, in that it had both completed a significant and transformative transaction and was re-establishing itself as a stand-alone entity. The ATLS compensation committee considered both individual and company performance of its NEOs based upon their outstanding performance and leadership until the closing of the Chevron Merger and ATLS successful establishment as a stand-alone entity, and shortly after the closing of the Chevron Merger in February 2011 awarded cash bonuses to Messrs. E. Cohen and J. Cohen as follows: Mr. E. Cohen $2,500,000 and Mr. J. Cohen $2,500,000. No amounts were allocated to us with respect to these awards.

After the end of ATLS 2011 fiscal year, the ATLS compensation committee recommended incentive awards pursuant to the Senior Executive Plan based on the prior year s performance. In determining the actual amounts to be paid to the NEOs, the ATLS compensation committee considered both individual and company performance. The Chairman of our General Partner made recommendations of incentive award amounts based upon ATLS performance as well as the performance of its subsidiaries; however, the ATLS compensation committee had the discretion to approve, reject, or modify the recommendations. The ATLS compensation committee noted that ATLS total unitholder return was 67% during 2011 and that its cash distributions increased by approximately 600% over the prior year; ATLS was able to reestablish its partnership fund raising programs despite the abbreviated sales period; ATLS management team worked throughout the year to prepare for the spin-off of its E&P and partnership management business to Atlas Resource Partners, in which ATLS will retain an approximate 80% interest, and successfully rebuilt its operations team after the transfer of senior executives and technical staff to Chevron; ATLS made fresh entries into the Marcellus Shale in areas not restricted by its non-competition agreement with Chevron, and increased its drilling in Tennessee, Colorado and Ohio;

and that we had operated our plants at full capacity, declared distributions at a sharp increase from the prior year, continued to expand capacity and distributable cash flow through organic growth and enjoyed multiple credit rating upgrades. In addition, the ATLS compensation committee reviewed the calculations of ATLS distributable cash flow and determined that 2011 distributable cash flow exceeded the pre-determined minimum threshold of 80% of the budgeted distributable cash flow of $84,498,000. The ATLS compensation committee determined that based upon the strong performance of the NEOs as highlighted above, the bonuses for the NEOs were as follows: Mr. E. Cohen $3,500,000, Mr. Dubay $1,000,000 and Mr. J. Cohen $3,000,000. The bonuses awarded to the NEOs did not exceed 55% of the maximum bonus allocable to each NEO under the Senior Executive Plan formula, and were reduced in part in recognition of the cash bonus awards made in February for service until the date of such bonuses.

Discretionary Bonuses. Messrs. Karlovich and Shrader are not participants in the Senior Executive Plan. The ATLS compensation committee awarded them discretionary bonuses as follows: Mr. Karlovich $350,000 and Mr. Shrader $375,000. Among other factors, the discretionary bonuses were awarded based on performance in connection with the sale of our 49% non-controlling interest in Laurel Mountain and the acquisition of our 20% interest in West Texas LPG Pipeline Limited Partnership.

Long-Term Incentives. Immediately after the Chevron Merger, the ATLS compensation committee recognized that the leadership of its NEOs was essential to ATLS as it established itself as a stand-alone entity. It further concluded that strong incentive for its NEOs to remain with ATLS for a significant period of time and their close alignment with its unitholders is critical in attracting and retaining additional key employees. However, the ATLS compensation committee further understood that its NEOs had received substantial cash amounts from Chevron in connection with the Chevron Merger, both as a result of the termination payments due under their employment agreements with AEI, which are described under Employment Agreements and Potential Payments Upon Termination or Change of Control, and their equity holdings in AEI, and that could have left its NEOs without the adequate financial incentives to continue employment with ATLS for a significant period of time, which the ATLS compensation committee considered important. To provide such incentives and alignment, ATLS made certain long-term incentive grants to our NEOs in March 2011 under the ATLS Plans as follows: Mr. E. Cohen- 300,000 phantom units and 700,000 options; Mr. Dubay 80,000 phantom units and 100,000 options; Mr. Kalamaras 50,000 phantom units and 70,000 options; Mr. J. Cohen 250,000 phantom units and 500,000 options; Mr. Karlovich 10,000 phantom units and 10,000 options and Mr. Shrader 30,000 phantom units. The ATLS compensation committee intended the awards to represent multi-year long-term incentive grants competitive with the 75th percentile of the market. For each of the NEOs, consistent with Mercer s advice, the grants represented between 3.5 to 5.4 times the annual market long-term incentive level from Mercer s survey. The awards will vest 25% on the third anniversary of the grant and 75% on the fourth anniversary.

In connection with his appointment as our CFO in November 2011, the ATLS compensation committee determined to award Mr. Karlovich a one-time award of 40,000 phantom units under our 2010 LTIP. The units will vest 25% each year, on the anniversary of the grant, over a four year period.

The following tables set forth the compensation allocation to us for fiscal years 2011, 2010 and 2009 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.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Stock Awards(1)	Option Awards(2)	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Eugene N. Dubay,	2011	$ 500,000	$	$ 1,778,400	$ 993,000	$ 1,000,000	$ 5,136,128(3)	$ 9,407,528
CEO and	2010	500,000	1,000,000	1,334,009	1,008,700		26,484	3,869,193
President	2009	438,847	500,000		564,000		555,805	2,058,652
Robert W.	2011	220,192	350,000	1,628,300	99,300		69,188(5)	2,366,980
Karlovich, III,	2010	179,358	63,000	304,200			9,538	556,096
CFO(4)	2009	152,255	73,308	48,000				273,563
Eric T.	2011	274,577		1,111,500	695,100		94,486(7)	2,175,663
Kalamaras,	2010	274,519	180,000	660,020(8)	273,790		49,572	1,437,901
Former CFO(6)	2009	76,923	152,917	66,620				296,460
Edward E. Cohen,	2011	101,423				525,000	25,650(10)	652,073
Chairman of the	2010	150,000				750,000	3,375	903,375
Board(9)	2009	147,577				375,000	12,600	535,177
Jonathan Z.	2011	72,115				450,000	21,375(10)	543,490
Cohen, Vice Chairman of Atlas	2010	105,000				600,000	1,688	706,688
Pipeline GP(9)	2009	101,539				300,000	7,863	409,402
Gerald R.	2011	290,000	375,000	666,900			95,474(11)	1,427,374
Shrader, Chief	2010	274,519	215,000	630,640 (8)			23,646	1,143,805
Legal Officer	2009	224,616	300,000	96,000				620,616

(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 16 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 16 for further discussion regarding assumptions made in valuation of fair value.

(3) Includes payments on DERs of $45,600 with respect to the phantom units awarded under the ATLS Plans and $27,842 with respect to the phantom units awarded under our Plans. Also includes amounts paid by Chevron in connection with the termination of Mr. Dubay s employment agreement as a result of the Chevron Merger as follows: $879,712 severance and $4,182,865 for the cash-out of equity awards subject to accelerated vesting, representing 15,454 stock awards reported in the Unit awards column for 2010 and 145,000 options reported in Option awards column for 2009 and 2010. See Employment Agreements and Potential Payments Upton Termination or Change of Control Eugene N. Dubay 2009 Employment Agreement and 2011 Option Exercises and Stock Vested table.

(4) On October 31, 2011, Robert W. Karlovich, III was appointed to serve in the capacity of Chief Financial Officer of our General Partner, a position previously held by Mr. Kalamaras.

(5) Includes payments on DERs of $5,700 with respect to the phantom units awarded under the ATLS Plans and $58,895 with respect to the phantom units awarded under our Plans.

(6) Eric T. Kalamaras resigned as the Chief Financial Officer of our General Partner, effective October 31, 2011. All stock and option awards, which were outstanding at that time, were forfeited.

(7) Includes payments on DERs of $16,500 with respect to the phantom units awarded under the ATLS Plans and $68,820 with respect to the phantom units awarded under our Plans. Also includes $316,350 for the cash-out of AEI equity Mr. Kalamaras held, as a result of the Chevron Merger.

(8) Reflects a change from what was reported in our Form 10-K for fiscal year 2010 to now reflect the cash bonus units that had been converted to phantom units during 2010.

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

(10) Reflects payments of DERs with respect to phantom units awarded under the ATLS Plans.

(11) Includes payments on DERs of $17,100 with respect to the phantom units awarded under the ATLS Plans and $77,108 with respect to the phantom units awarded under our Plans.

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.	N/A	N/A	$ 3,249,000	03/25/11	80,000[4]		$	$ 1,778,400
Dubay				03/25/11		100,000[5]	22.23	993,000
Robert W.	N/A	N/A	N/A	03/25/11	10,000[4]			222,300
Karlovich, III				03,25/11		10,000[5]	22.23	93,300
				11/04/11	40,000[6]			1,406,000
Eric T.	N/A	N/A	N/A	03/25/11	50,000[4]			1,111,500
Kalamaras[7]				03,25/11		70,000[5]	22.23	695,100
Edward E.	N/A	N/A	7,673,000	03/25/11	300,000[8]			6,669,000
Cohen				03,25/11		700,000[9]	22.23	6,951,000
Jonathan Z.	N/A	N/A	5,461,000	03/25/11	250,000[8]			5,557,500
Cohen				03,25/11		500,000[9]	22.23	4,965,000
Gerald R. Shrader	N/A	N/A	N/A	03/25/11	30,000[4]			666,900

(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 or our 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 the ATLS 2010 Plan.

(5) Represents options granted under the ATLS 2010 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 $9.93.

(6) Represents phantom units granted under our 2010 Plan.

(7) Units and options were forfeited upon Mr. Kalamaras resignation effective October 31, 2011.

(8) Represents phantom units granted under the ATLS 2010 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.

(9) Represents options granted under the ATLS 2010 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 $9.93. Unit options 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.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

2004 Employment Agreement

In May 2004, AEI entered into an employment agreement with Edward E. Cohen, who currently serves as our Chairman and, from 1999 until January 2009, served as our CEO. The agreement was amended as of December 31, 2008 to comply with requirements under Section 409A of the Code relating to deferred compensation. Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, and ATLS entered into a new employment agreement with Mr. Cohen on May 13, 2011. The following discussion of Mr. Cohen s employment agreement summarizes the elements of Mr. Cohen s compensation that were allocated to us in part.

Mr. Cohen s employment agreement required him to devote such time to AEI as was reasonably necessary to the fulfillment of his duties, although it permitted him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $350,000 per year, which could be increased by the AEI compensation committee based upon its evaluation of Mr. Cohen s performance. Mr. Cohen was eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment.

The agreement had a term of three years and, until notice to the contrary, the term was automatically extended so that on any day on which the agreement was in effect it had a then-current three-year term. Mr. Cohen s former employment agreement was entered into in 2004, around the time that AEI was preparing to launch its initial public offering in connection with its spin-off from Resource America, Inc. At that time, it was important to establish a long-term commitment to and from Mr. Cohen as the Chief Executive Officer and then-current President of AEI. The rolling three-year term was determined to be an appropriate amount of time to reflect that commitment and was deemed a term that was commensurate with Mr. Cohen s position. The multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the agreement was negotiated.

The agreement provided the following regarding termination and termination benefits:

- Upon termination of employment due to death, Mr. Cohen s estate will receive (a) a lump sum payment in an amount equal to three times his final base salary and (b) automatic vesting of all stock and option awards.

- AEI may terminate Mr. Cohen s employment if he is disabled for 180 consecutive days during any 12-month period. If his employment is terminated due to disability, Mr. Cohen will receive (a) a lump sum payment in an amount equal to three times his final base salary, (b) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by AEI s employees, during the three years following his termination, (c) a lump sum amount equal to the cost AEI would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by our employees, (d) automatic vesting of all stock and option awards and (e) any amounts payable under AEI s long-term disability plan.

- AEI may terminate Mr. Cohen s employment without cause, including upon or after a change of control, upon 30 days prior written notice. He may terminate his employment for good reason. Good reason is defined as a reduction in his base pay; a demotion; a material reduction in his duties; relocation; his failure to be elected to AEI s Board of Directors; or AEI s material breach of the agreement. Mr. Cohen must provide AEI with 30 days notice of a termination by him for good reason within 60 days of the event constituting good reason. AEI then would have 30 days in which to cure and, if it does not do so, Mr. Cohen s employment will terminate 30 days after the end of the cure period. If employment is terminated by AEI without cause, by Mr. Cohen for good reason or by either party in connection with a change of control, he will be entitled to either (a) if Mr. Cohen does not sign a release, severance benefits under AEI s then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three times his average compensation (defined as the average of the three highest years of total compensation), (ii) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by AEI s employees, during the three years following his termination, (iii) a lump sum amount equal to the cost AEI would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by AEI s employees, and (iv) automatic vesting of all stock and option awards.

Mr. Cohen may terminate the agreement without cause with 60 days notice to AEI, and if he signs a release, he will receive (a) a lump sum payment equal to one-half of one year s base salary then in effect and (b) automatic vesting of all stock and option awards. Change of control was defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act of 1933, of 25% or more of AEI s voting securities or all or substantially all of AEI s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

AEI consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were AEI s directors immediately before the transaction and AEI s chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) AEI s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;

during any period of 24 consecutive months, individuals who were AEI Board members at the beginning of the period cease for any reason to constitute a majority of the AEI Board, unless the election or nomination for election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

AEI s stockholders approve a plan of complete liquidation or winding up of AEI, or agreement of sale of all or substantially all of AEI s assets or all or substantially all of the assets of AEI s primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. In the event that any amounts payable to Mr. Cohen upon termination become subject to any excise tax imposed under Section 4999 of the Code, AEI must pay Mr. Cohen an additional sum such that the net amounts retained by Mr. Cohen, after payment of excise, income and withholding taxes, equals the termination amounts payable, unless Mr. Cohen s employment terminates because of his death or disability.

When Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $60,354,580 for the cash-out of the AEI equity he held, $17,872,308 in severance, $71,842 in benefits payments and $6,052,204 for excise tax gross-up.

2011 Employment Agreement

On May 13, 2011, ATLS entered into a new 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 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 (or $1,000,000 if the period of employment ended before the 2011 annual bonuses had been paid), (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.

Good reason is defined under the agreement as:

- a material reduction in Mr. Cohen s base salary;
- a demotion from his position;
- material reduction in Mr. Cohen s duties, it being deemed such a material reduction if ATLS ceases to be a public company unless ATLS becomes a subsidiary of a public company and Mr. Cohen becomes the chief executive officer of the public parent immediately following the applicable transaction;
- Mr. Cohen is required to relocate to a location more than 35 miles from his previous location;
- Mr. Cohen ceases to be elected to ATLS board; or
- any material breach of the agreement.

Cause is defined as:

- Mr. Cohen is convicted of a felony, or any crime involving fraud or embezzlement;
- Mr. Cohen intentionally and continually fails to perform his reasonably assigned duties (other than as a result of disability), which failure is materially and demonstrably detrimental to ATLS and has continued for 30 days after written notice signed by a majority of the independent directors of ATLS general partner; or
- Mr. Cohen is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

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, 2011.

Reason for Termination	**Lump Sum Severance Payment**	**Benefits[1]**	**Accelerated Vesting of Equity Awards**
Death	$ 525,000	$	$
Disability	525,000	7,722	
Termination by us without cause or by Mr. Cohen for good reason	765,000[2]	7,722	

(1) Dental and medical benefits were calculated using 2011 COBRA rates.
(2) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Jonathan Z. Cohen

2009 Employment Agreement

In January 2009, AEI entered into an employment agreement with Jonathan Z. Cohen, who currently serves as the Vice Chairman of our General Partner. Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, and ATLS entered into a new employment agreement with Mr. Cohen on May 13, 2011.

Mr. Cohen s employment agreement required him to devote such time to AEI as was reasonably necessary to the fulfillment of his duties, although it permitted him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $600,000 per year, which could be increased by the AEI board based upon its evaluation of Mr. Cohen s performance. Mr. Cohen was eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment. The agreement had a term of three years and, until notice to the contrary, the term was automatically extended so that on any day on which the agreement was in effect it had a then-current three-year term. The rolling three-year term and the multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the employment agreement was negotiated.

The agreement provided the following regarding termination and termination benefits:

Upon termination of employment due to death, Mr. Cohen s estate will receive (a) accrued but unpaid bonus and vacation pay and (b) automatic vesting of all equity-based awards.

AEI may terminate Mr. Cohen s employment without cause upon 90 days prior notice or if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and AEI s board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by AEI other than for cause, including disability, or by Mr. Cohen for good reason (defined as any action or inaction that constitutes a material breach by AEI of the employment agreement or a change of control), Mr. Cohen will receive either (a) if Mr. Cohen does not sign a release, severance benefits under our then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three years of his average compensation (which is defined as his base salary in effect immediately before termination plus the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurred), less, in the case of termination by reason of disability, any amounts paid under disability insurance provided by us, (ii) monthly reimbursement of any COBRA premium paid by Mr. Cohen, less the amount Mr. Cohen would be required to contribute for health and dental coverage if he were an active employee and (iv) automatic vesting of all equity-based awards.

AEI may terminate Mr. Cohen s employment for cause (defined as a felony conviction or conviction of a crime involving fraud, deceit or misrepresentation, failure by Mr. Cohen to materially perform his duties after notice other than as a result of physical or mental illness, or violation of confidentiality obligations or representations contained in the employment agreement). Upon termination by AEI for cause or by Mr. Cohen for other than good reason, Mr. Cohen s vested equity-based awards will not be subject to forfeiture.

Change of control was defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 25% or more of AEI s voting securities or all or substantially all of AEI s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

AEI consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were our directors immediately before the transaction and AEI s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) AEI s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;

during any period of 24 consecutive months, individuals who were AEI board members at the beginning of the period cease for any reason to constitute a majority of AEI s board, unless the election or nomination for election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

AEI s stockholders approve a plan of complete liquidation or winding up, or agreement of sale of all or substantially all of AEI s assets or all or substantially all of the assets of its primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. When Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $36,837,883 for the cash-out of the AEI equity he held and $8,600,000 in severance.

2011 Employment Agreement

On May 13, 2011, ATLS entered into a new 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 added 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 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 ATLS 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 (or $250,000 if the period of employment ended before the 2011 annual bonuses had been paid), (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.

Good reason is defined under the agreement as:

- a material reduction in Mr. Cohen s base salary;
- a demotion from his position;
- a material reduction in Mr. Cohen s duties, it being deemed such a material reduction if ATLS ceases to be a public company unless it becomes a subsidiary of a public company and Mr. Cohen becomes an executive officer of the public parent with responsibilities substantially equivalent to his previous position immediately following the applicable transaction;
- Mr. Cohen is required to relocate to a location more than 35 miles from his previous location;
- Mr. Cohen ceases to be elected to ATLS board; or
- any material breach of the agreement.

Cause is defined as:

- Mr. Cohen is convicted of a felony, or any crime involving fraud or embezzlement;
- Mr. Cohen intentionally and continually fails to perform his reasonably assigned duties (other than as a result of disability), which failure is materially and demonstrably detrimental to ATLS and has continued for 30 days after written notice signed by a majority of the independent directors of ATLS general partner; or
- Mr. Cohen is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

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, 2011.

Reason for Termination	Lump Sum Severance Payment	Benefits[1]	Accelerated Vesting of Equity Awards
Death	$ 450,000	$	$
Disability	450,000	11,131	
Termination by us without cause or by Mr. Cohen for good reason	562,500 [2]	11,131	

(1) Dental and medical benefits were calculated using 2011 COBRA rates.
(2) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Eugene N. Dubay

2009 Employment Agreement

In January 2009, AEI entered into an employment agreement with Eugene N. Dubay, who currently serves as our President and CEO. Mr. Dubay s employment agreement terminated in February 2011 in connection with the Chevron Merger, and ATLS entered into a new employment agreement with Mr. Dubay on November 4, 2011. AEI historically allocated all of Mr. Dubay s compensation cost to us.

The agreement provided for an initial base salary of $400,000 per year and a bonus of not less than $300,000 for the period ending December 31, 2009. After that, bonuses would be awarded solely at the discretion of AEI s compensation committee. In addition to reimbursement of reasonable and necessary expenses incurred in carrying out his duties, Mr. Dubay was entitled to reimbursement of up to $40,000 for relocation costs and AEI agreed to purchase his residence in Michigan for $1,000,000. The agreement provided that if Mr. Dubay s employment was terminated before June 30, 2011 by him without good reason or by AEI for cause, Mr. Dubay must repay an amount equal to the difference between the amount AEI paid for his residence and its fair market value on the date acquired by AEI. Upon execution of the agreement, Mr. Dubay was granted the following equity compensation:

Options to purchase 100,000 shares of AEI s common stock, which vest 25% per year on each anniversary of the effective date of the agreement;

Options to purchase 100,000 of our common units, which vest 25% per year on each anniversary of the effective date of the agreement; and

Options to purchase 100,000 of ATLS common units, which vest 25% on the third anniversary, and 75% on the fourth anniversary, of the effective date of the agreement.

The agreement had a term of two years and, until notice to the contrary, his term was automatically renewed for one year renewal terms. AEI may terminate the agreement:

at any time for cause;

without cause upon 45 days prior written notice;

- if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and AEI s and ATLS board of directors determine, in good faith based upon medical evidence, that he is unable to perform his duties; or

- in the event of Mr. Dubay s death.

Mr. Dubay had the right to terminate the agreement for good reason, including a change of control. Mr. Dubay must provide notice of a termination by him for good reason within 30 days of the event constituting good reason. Termination by Mr. Dubay for good reason was only effective if such failure has not been cured within 90 days after notice is given to AEI. Mr. Dubay could also terminate the agreement without good reason upon 60 days notice. Termination amounts will not be paid until six months after the termination date, if such delay is required by Section 409A of the Internal Revenue Code.

Cause was defined as:

- the commitment of a material act of fraud;

- illegal or gross misconduct that is willful and results in damage to AEI s business or reputation;

- being charged with a felony;

- continued failure by Mr. Dubay to perform his duties after notice other than as a result of physical or mental illness; or

- Mr. Dubay s failure to follow AEI s reasonable written directions consistent with his duties.

Good reason was defined as any action or inaction that constitutes a material breach by AEI of the agreement or a change of control.

Change of control was defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 50% or more of AEI s voting securities or all or substantially all of AEI s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with AEI or Mr. Dubay or any member of his immediate family;

- AEI consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction of AEI other than with a related entity, in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of directors of the surviving entity, unless 1/2 of the surviving entity s board were AEI directors immediately before the transaction and AEI s CEO immediately before the transaction continues as the CEO of the surviving entity; or (b) AEI s voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;

- during any period of 24 consecutive calendar months, individuals who were AEI board members at the beginning of the period cease for any reason to constitute a majority of AEI s board, unless the election or nomination for the election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors