ATLAS PIPELINE PARTNERS LP
Form 10-K
February 25, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

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	**(I.R.S. Employer**

incorporation or organization)	Identification No.)
1550 Coraopolis Heights Road	
Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (412) 262-2830

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 ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and small reporting company in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer	¨	Accelerated filer	x
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 $9.66 per common limited partner unit on June 30, 2010, was approximately $445.6 million.

The number of common units of the registrant outstanding on February 22, 2011 was 53,338,422.

DOCUMENTS INCORPORATED BY REFERENCE: None

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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FORWARD-LOOKING STATEMENTS

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

- *the demand for natural gas and natural gas liquids;*
- *the price volatility of natural gas and natural gas liquids;*
- *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.

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Glossary of Terms

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

Bbl	Barrel - measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BPD	Barrels per day
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.
Distributable Cash Flow (DCF)	Net income plus depreciation, amortization, other non-cash expenses and maintenance capital expenditures. Used to determine the amount of cash flow available to distribute to units holders.
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
Keep-Whole	Contract with producer whereby plant operator pays for or returns an equivalent BTU of 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 Exchange Commission
Y-grade	A term utilized in the industry for the NGL stream prior to fractionation, also referred to as raw mix.

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PART I

ITEM 1. BUSINESS

Corporate Structure

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering, processing and treating services in the Anadarko and Permian Basins located in the southwestern and mid-continent regions of the United States and a provider of natural gas gathering services in the Appalachian Basin in the northeastern 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. (Atlas Energy, L.P. or AHD), a publicly traded Delaware limited partnership (NYSE: AHD) which owned a 10.8% limited partner interest, as well as the 2% general partner interest in us, at December 31, 2010. Atlas Energy, Inc. (Atlas Energy, Inc. or ATLS), a formerly publicly-traded company, owned 64.0% of the common units of AHD and also had a direct 2.1% interest in us through ownership in our common units, plus 8,000 $1,000 par value 12% Class C cumulative preferred limited partner units at December 31, 2010.

The following chart displays the corporate organizational structure as of December 31, 2010:

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Recent Developments

Elk City Sale

On September 16, 2010, we completed the sale of our Elk City and Sweetwater, Oklahoma natural gas gathering systems, the related processing and treating facilities and the Nine Mile processing plant (collectively Elk City) to a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) for $682 million in cash, excluding working capital adjustments and transaction costs. We utilized the proceeds from the sale to repay our senior secured term loan and a portion of our indebtedness under the revolving credit facility.

Laurel Mountain Sale

On February 17, 2011, we completed a sale to Atlas Energy Resources LLC (Atlas Energy Resources) of our 49% non-controlling interest in Laurel Mountain (the Laurel Mountain Sale) for $413.5 million in cash, including adjustments based on certain 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.

AHD Transaction Agreement

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

Atlas Energy, Inc. Merger

Concurrently with the AHD Transactions, ATLS completed an agreement and plan of merger with Chevron Corporation, a Delaware corporation (Chevron), pursuant to which, among other things, ATLS became a wholly-owned subsidiary of Chevron (the Chevron Merger). Our common units and 12% cumulative Class C preferred units held directly by ATLS were acquired by Chevron as part of the Chevron Merger.

Atlas Pipeline Holdings, L.P. Name Change

On February 18, 2011, subsequent to the AHD Transactions and the Chevron Merger, AHD changed its name to Atlas Energy, L.P.

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The following chart displays the corporate organizational structure subsequent to the Chevron Merger and AHD Transaction Agreement and related developments described above:

The remainder of this Business section discusses our business as it existed on December 31, 2010, without giving effect to the Laurel Mountain Sale or AHD Transactions or the Chevron Merger.

General

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

In our Mid-Continent operations, we own and operate five natural gas processing plants with aggregate capacity of approximately 520 MMCFD. These facilities are connected to approximately 8,600 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gathers gas from wells and central delivery points and delivers the natural gas to our processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are conducted principally through our 49% non-controlling ownership interest in the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which owns and operates approximately 1,000 miles of natural gas gathering systems in the Appalachian Basin located in Pennsylvania. We also own and operate approximately 70 miles of active natural gas gathering pipelines located in Tennessee.

Our 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; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin and the Marcellus Shale in the Appalachian Basin. In the Mid-Continent, our gathering systems are connected to approximately 7,700 central delivery points or wells. In Appalachia, Laurel Mountain s systems are connected to approximately 4,700 wells. Thus, we believe that 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

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

Laurel Mountain gathers the majority of the natural gas from wells operated by Atlas Energy Resources and its subsidiaries. Laurel Mountain has gas gathering agreements with Atlas Energy Resources under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations).

In July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering systems and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas.

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. Our recent construction of the Consolidator Plant in West Texas is an example of executing this strategy. Other opportunities include pursuing relationships with new producers, the elimination of pipeline bottlenecks, reducing operating line pressures and focusing on a reduction of pipeline losses along our gathering systems.

Expanding operations through organic growth projects and pursuing strategic acquisitions. We continue to explore opportunities to expand our existing infrastructure. We also plan to pursue strategic acquisitions that are accretive to our unitholders, by seeking acquisition 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 crude oil, 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 that 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 many other areas, such as our Chaney Dell, Midkiff/Benedum and Velma operations in the Mid-Continent, are 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 (low 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.

Natural gas transportation pipelines receive natural gas from producers, other mainline transportation pipelines, shippers and gathering systems through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial end-users, utilities and other pipelines. Generally natural gas transportation agreements generate revenue for these systems 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. Primary contracts are Fee-Based, Percentage of Proceeds (POP) and Keep-Whole (see Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual

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Revenue Arrangements).

Our Mid-Continent Operations

We own and operate approximately 8,600 miles of intrastate natural gas gathering systems located in Oklahoma, Kansas, and Texas. We also own and operate five processing plants located in Oklahoma and Texas. Our gathering, processing and treating assets service long-lived natural gas regions, including the Permian and Anadarko Basins. Our systems gather natural gas from oil and natural gas wells and process the raw natural gas into residue gas by extracting NGLs and removing impurities. In the aggregate, our Mid-Continent systems have approximately 7,700 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 ONEOK Hydrocarbon, L.P.

Mid-Continent Overview

We consider the Mid-Continent region as running from Kansas through Oklahoma and Texas, branching into Louisiana, as well as southeastern New Mexico and western Arkansas (see the highlighted area of the map below). Two of the primary producing areas in the region include the Anadarko Basin and the Permian Basin, which is where our Mid-Continent systems are located.

Mid-Continent Gathering Systems

Chaney Dell. The Chaney Dell gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. As of December 31, 2010, the gathering systems had approximately 4,300 miles of active natural gas gathering pipelines with approximately 4,300 receipt points. The primary producers on the Chaney Dell gathering system include certain subsidiaries of Chesapeake Energy Corporation; Sandridge Exploration and Production, LLC; and Bluestem Marketing, LLC.

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Midkiff/Benedum. The Midkiff/Benedum gathering system, which we operate and in which we have an approximate 72.8% ownership, as of December 31, 2010, had approximately 3,100 miles of active natural gas gathering pipelines and approximately 2,800 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 Midkiff/Benedum system. The primary producers on the Midkiff/Benedum 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. As of December 31, 2010, the gathering system had 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 certain subsidiaries of Chesapeake Energy Corporation; Range Resources; and XTO Energy, Inc.

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Mid-Continent Processing and Treating Plants

Chaney Dell. The Chaney Dell system processes natural gas through the Waynoka and Chester plants, which are active cryogenic natural gas processing facilities. The Chaney Dell system s processing operations have total capacity of approximately 228 MMCFD. The Waynoka processing plant, located in Woods County, Oklahoma began operations in December 2006 and became fully operational in July 2007. The Chaney Dell plant located in Major County is inactive. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Waynoka and Chester plants and sell NGL production to ONEOK Hydrocarbon, L.P.

Midkiff/Benedum. The Midkiff/Benedum system processes natural gas through the Consolidator (located at 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 currently inactive. The Benedum plant is a 45 MMCFD cryogenic facility in Upton County, Texas. Our Consolidator/Benedum processing operations have an aggregate processing capacity of approximately 195 MMCFD. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Consolidator/Benedum 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 capacity of approximately 100 MMCFD. The Velma plant is one of only two facilities in the area that is 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

In the Mid-Continent, we have natural gas purchase, gathering and/or processing agreements with approximately 560 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 Mid-Continent producers. For instance, we have producer relationships going back over 20 years on our Velma System. Several of our top producers, which accounted for a significant portion of our Velma volumes for the year ended December 31, 2010, have contracts with primary terms running into 2019 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 Midkiff/Benedum 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 that 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 that 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 that is 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, an intrastate pipeline; Southern Star Central Gas Pipeline, Inc. and Natural Gas Pipeline Company of America, interstate pipelines. The Chester plant has access to Panhandle Eastern Pipe Line Company, LP and the Waynoka plant has access to Enogex LLC, Panhandle Eastern Pipe Line Company, LP and Southern Star Central Gas Pipeline, Inc. The Consolidator/Benedum plants have access to Kinder Morgan Texas Pipeline, Northern Natural Gas Company and El Paso Natural Gas Company. As negotiated in specific agreements, various producers are allowed to take their share of gas in-kind at various delivery points.

We sell our NGL production to ONEOK Hydrocarbon, L.P. under three separate agreements. The Velma agreement has an initial term expiring in 2016, the Midkiff/Benedum agreement has an initial term expiring in 2013, and the Chaney Dell agreement has a term expiring in 2014. 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 Chaney Dell plants and around the Chaney Dell gathering system is currently sold to Plains Marketing. Condensate collected at the Consolidator/Benedum plants and around the Midkiff/Benedum gathering system is currently sold to Plains Marketing, Occidental Energy Marketing, Inc. and Oasis Marketing and Transportation Corporation.

Commodity Risk Management

Our Mid-Continent 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 that is 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 (i) price relationship between the physical and financial instrument deteriorating or (ii) projected physical volumes changing.

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We (a) purchase natural gas and subsequently sell processed natural gas and the resulting NGLs, or (b) purchase natural gas and subsequently sell the unprocessed natural gas, or (c) gather and/or process the natural gas for a fee without taking title to the commodities. Scenario (b) exposes us to a generally neutral price risk (long sales approximate short purchases), while scenario (c) does not expose us to any price risk; in both scenarios, risk management is not required. Scenario (a) does involve commodity price risk.

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 or by utilizing the purchase or sale of options, which result in floor prices or ceiling prices. 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 in other income 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 for commodities that are not traded on an open market. To ensure that 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, 2010, please see Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Our Appalachia Operations

Our Appalachia operations are principally conducted through our 49% non-controlling interest in Laurel Mountain, which we sold subsequent to December 31, 2010. Laurel Mountain owns and operates approximately 1,000 miles of intrastate gas gathering systems located in Pennsylvania, including substantial assets in the Marcellus Shale. We also own and operate approximately 70 miles of natural gas gathering pipelines in Tennessee. Laurel Mountain serves approximately 4,700 wells and experienced an average throughput of 109.5 MMCFD of natural gas for the year ended December 31, 2010. Our Tennessee systems serve approximately 180 receipt points and experienced an average throughput of 8.7 MMCFD of natural gas for the year ended December 31, 2010. These gathering systems provide a means through which well owners and operators can transport the natural gas produced by their wells to interstate and public utility pipelines for delivery to customers. To a lesser extent, the gathering systems transport natural gas directly to customers. Laurel Mountain s systems are located in the Appalachian Basin, which encompasses the Marcellus Shale. The Marcellus Shale is a vast, newly developing shale play experiencing a significant increase in natural gas exploration and production. The Appalachian Basin is a region that has historically been characterized by long-lived, predictable natural gas reserves that are close to major eastern U.S. natural gas markets. Substantially all of the natural gas Laurel Mountain gathers in the Appalachian Basin is derived from wells operated by Atlas

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Energy Resources. Laurel Mountain has a gas gathering agreement with Atlas Energy Resources, which is intended to maximize the use and expansion of the gathering systems and the amount of natural gas which Laurel Mountain gathers in the region. In addition, other natural gas producers have acreage positions in relatively close proximity to Laurel Mountain s current and planned assets, providing additional opportunities for expansion.

Appalachian Basin Overview

The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. The Appalachian Basin is strategically located near the energy-consuming regions of the mid-Atlantic and northeastern United States.

Natural Gas Supply

Substantially all of the natural gas Laurel Mountain gathers in the Appalachian Basin is derived from wells operated by Atlas Energy Resources. Laurel Mountain s ability to increase the flow of natural gas through its gathering systems will be determined primarily by the number of wells drilled by Atlas Energy Resources and connected to the gathering systems; and Laurel Mountain s ability to acquire additional gathering assets and secure gathering contracts with other natural gas producers with acreage positions in the area and expand existing systems. During the year ended December 31, 2010, approximately 90 wells were connected to the Laurel Mountain gathering system.

Natural Gas Revenue

Our Appalachia revenue is determined primarily by the amount of natural gas flowing through Laurel Mountain s and our Tennessee gathering systems and the price received for this natural gas. Laurel Mountain has an agreement with Atlas Energy Resources under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). For the year ended December 31, 2010, Laurel Mountain received gathering fees averaging $0.95 per MCF.

Because we do not buy or sell gas in connection with our Appalachia operations, we do not engage in hedging activities. Atlas Energy Resources maintains a hedging program. Since Laurel Mountain receives gathering fees from Atlas Energy Resources generally based on the selling price received by Atlas Energy Resources, inclusive of the effects of financial and physical hedging, these financial and physical hedges mitigate the risk of Laurel Mountain s arrangements.

Our Relationship with Atlas Energy, Inc.

We began our operations in January 2000 by acquiring the Appalachia gathering systems of ATLS In May, 2009, we contributed the majority of our Appalachia gathering system assets to Laurel Mountain, a joint venture in which we have a 49% non-controlling ownership interest. ATLS owned 64.0% of AHD, the parent of our general partner, which owned a 10.8% limited partner interest and a 2% general partner interest in us at December 31, 2010.

ATLS and its affiliates sponsor limited and general partnerships to raise funds from investors to explore for, develop and produce natural gas and, to a lesser extent, oil from locations in northeastern Appalachia. Laurel Mountain s gathering systems are connected to approximately 4,600 wells developed and operated by Atlas Energy Resources in the Appalachian Basin. Laurel Mountain gathers substantially all of the natural gas from wells operated by Atlas Energy Resources.

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Natural Gas Gathering Agreements

In connection with the formation of Laurel Mountain, on June 1, 2009, Laurel Mountain entered into the following natural gas gathering agreements with Atlas Energy Resources, Atlas Energy Operating Company, LLC, Atlas America, LLC, Atlas Noble, LLC, Resource Energy, LLC and Viking Resources, LLC: (1) a gas gathering agreement for natural gas on the Legacy Appalachia system with respect to the existing gathering systems and any expansions to it (the Legacy Agreement) and (2) a gas gathering agreement for natural gas on the expansion gathering system with respect to other gathering systems constructed within a specified area of mutual interest (the Expansion Agreement and collectively with the Legacy Agreement, the Gathering Agreements). Under these Gathering Agreements, Atlas Energy Resources will dedicate its natural gas production in the Appalachian Basin to Laurel Mountain for transportation to interstate pipeline systems, local distribution companies, and/or end users in the area, subject to certain exceptions. In return, Laurel Mountain is required to accept and transport Atlas Energy Resources dedicated natural gas in the Appalachian Basin subject to certain conditions.

Under the Gathering Agreements, Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations).

The provisions in the Gathering Agreements regarding the allocation of responsibility for constructing additional gathering lines are that to the extent that Atlas Energy Resources own wells or propose wells that are within 2,500 feet of Laurel Mountain s gathering system, Laurel Mountain must, at its own cost, construct up to 2,500 feet of the gathering lines as necessary to connect such wells to the gathering system. For wells more than 2,500 feet from Laurel Mountain s gathering system, if Atlas Energy Resources construct a gathering line to within 1,000 feet of Laurel Mountain s gathering system, then Laurel Mountain must, at its own cost, extend its gathering system to connect to such gathering lines.

The Gathering Agreements remain in effect so long as gas from Atlas Energy Resources wells is produced in economic quantities without lapse of more than 90 days.

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 because as natural gas, crude oil and NGL prices increase the economic attractiveness of owning such assets increases.

Mid-Continent. In our Mid-Continent service area, 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, DCP Midstream, Enogex, LLC, Hiland Partners, Mustang Fuel Corporation, ONEOK Field Services, Southern Union Company, Targa Resources and West Texas Gas.

We believe that 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; and

- the quality and efficiency of the gathering systems and processing plants that will be utilized in delivering the gas to market; and

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the access to various residue markets that provides flexibility for producers and ensures that the gas will make it to market; and

the responsiveness to a well operator s needs, particularly the speed at which a new well is connected by the gatherer to its system. We believe that 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.

Appalachia. The assets operated in the Appalachian Basin by Laurel Mountain and us do not encounter direct competition in our service areas at this time, since Atlas Energy Resources controls the majority of the drillable acreage in the area. However, because these operations principally serve wells drilled by Atlas Energy Resources, we are affected by competitive factors affecting Atlas Energy Resources ability to obtain properties and drill wells, which affects our ability to expand gathering systems and to maintain or increase the volume of natural gas gathered and, thus, transportation revenues. Atlas Energy Resources also may encounter competition in obtaining drilling services from third-party providers. Any competition it encounters could delay Atlas Energy Resources in drilling wells, and thus delay the connection of wells to our gathering systems. These delays would reduce the volume of natural gas that otherwise would have been gathered, thus reducing potential transportation revenues.

In addition to the connections to Atlas Energy Resources wells, we seek to connect wells operated by third parties. As of December 31, 2010, these systems are connected to approximately 250 third party wells.

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 the Federal Energy Regulatory Commission (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, or Laurel Mountain s, gathering facilities may be subject to change based on future determinations by FERC and the courts.

Laurel Mountain s operations in Pennsylvania currently are not subject to the Pennsylvania Public Utility Commission s regulatory authority since Laurel Mountain does not provide service to the public generally and, accordingly, its activities do not constitute the operation of a public utility. In the event the Pennsylvania authorities seek to regulate Laurel Mountain s operations, our operating costs could increase and our transportation fees could be adversely affected, thereby reducing our net revenues and ability to fund our operations, pay required debt service on our credit facilities and make distributions to our General Partner and common unitholders.

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

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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 that 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.

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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, natural gas liquids 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 that our operations are in substantial compliance with applicable environmental laws and regulations and that 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 you that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes that are 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 hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

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We believe that 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 that 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 were material and we believe all of them have been 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. 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, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

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. The discharge of pollutants is prohibited unless authorized by a permit or other agency approval.

The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by a permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil or criminal penalties as well as significant remedial obligations. Further, natural gas extraction activities utilize a process called hydraulic fracturing, which results in water discharges that must be treated and disposed of in accordance with applicable regulatory requirements. Recently, this subject has received regulatory and legislative attention at both the federal and state levels, and it is possible that the permitting and compliance requirements applicable to hydraulic fracturing activity may become more stringent. Such requirements could have an adverse impact on our operations.

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 assure 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 that 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.

PHMSA recently finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transportation pipelines (including gathering lines) 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 that this will continue in the future.

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 that 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 that are registered with the U.S. Department of Homeland Security, or DHS, in order to identify the quantities of various chemicals that are 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 that are recovered and stored as a result of facility processing activities, and various chemicals utilized within the processes, have been identified

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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 the United States Congress is also considering legislation to address the production and reduction of greenhouse gases primarily through the planned development of a greenhouse gas cap and trade program. As an alternative to the cap and trade program, the EPA may implement greenhouse gas reduction through traditional construction and operating permit programs, which would effectively circumvent the need for congressional action. The cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. We could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. In addition, 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. However, we are currently unable to assess the timing and effect of the pending legislation.

Properties

As of December 31, 2010, our principal facilities in the Mid-Continent consist of five natural gas processing plants and approximately 8,600 miles of active 2 to 30 inch diameter pipeline. Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. As of December 31, 2010, our principal facilities in Appalachia include approximately 70 miles of 2 to 12 inch diameter pipeline operated by our Tennessee gathering systems and approximately 1,000 miles of 2 to 12 inch diameter pipeline operated by Laurel Mountain. 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.

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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)	2010 Average Througput (MMCFD)	2010 Average Utilization Rate
Velma plant	Stephens County, OK	Updated 2003	100	78	78%
Waynoka plant	Woods County, OK	2006	200		
Chester plant	Woodward County, OK	1981	28		
Total Chaney Dell			228	214	94%
Consolidator plant(1)	Reagan County, TX	2009	150		
Benedum plant	Upton County, TX	Updated 1981	45		
Total Midkiff/Benedum			195	163	84%

(1) Replaced 110 MMCFD Midkiff plant, which has been shut down. Midkiff plant is available for processing if natural gas supply increases beyond the Consolidator plant capacity.

Natural Gas Gathering Systems

System	Location	Approximate Active Miles of Pipe	Receipt Points
Chaney Dell	North Central Oklahoma and Southern Kansas	4,300	4,300
Velma	Southern Oklahoma and Northern Texas	1,200	600
Midkiff/Benedum	West Texas	3,100	2,800
Laurel Mountain	Pennsylvania	1,000	4,700
Tennessee	Tennessee	70	180

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 that 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 that are 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 270 people at December 31, 2010 who provided direct support to our operations.

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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.

On February 17, 2011, ATLS consummated its merger with Chevron pursuant to the Chevron Merger Agreement whereby ATLS became a wholly-owned subsidiary of Chevron. Additionally, on February 17, 2011, AHD consummated the AHD Transactions with ATLS and Atlas Energy Resources and subsequent to such transaction, AHD or one of its subsidiaries employs all of the persons responsible for our management and operations. See Recent Developments for further discussion.

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 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108, telephone number (412) 262-2830. 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.

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ITEM 1A. RISK FACTORS

Partnership interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to Our Business

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

The amounts of cash that 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 flow. Cash distributions do not depend directly on our profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when we record losses and may not be made during periods when we record profits. The actual amounts of cash we generate will depend upon numerous factors relating to our business which may be beyond our control, including:

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

the cost of acquisitions and capital improvements;

our issuance of equity securities;

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 hedging program and the creditworthiness of our hedging 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 that we will have available for distribution will depend on other factors, including:

the level of capital expenditures we make;

the sources of cash used to fund our acquisitions;

limitations on our access to capital or the market for our common units and notes;

our debt service requirements and requirements to pay dividends on our outstanding preferred units; and

the amount of cash reserves established by our General Partner for the conduct of our business.

Our financial and operating performance may fluctuate significantly from quarter to quarter. We may be unable to continue to generate sufficient cash flow to fund our operations, pay required debt service on our credit facility and make distributions to our unitholders. If we are unable to do so, we may be required to sell assets or equity, reduce capital expenditures, reduce or eliminate distributions to unit holders, refinance all or a portion of our existing indebtedness or obtain additional financing. We may be unable to do so on acceptable terms, or at all.

We cannot borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings under our partnership agreement. Because we cannot borrow money to pay distributions unless we establish a facility that meets the definition contained in our partnership agreement, our ability to pay a distribution in any quarter is solely dependent on our ability to generate sufficient operating surplus with respect to that quarter.

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 the future, may impact the cash that we have available to fund our operations, pay required debt service on our credit facility and make distributions to our unitholders.

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Potential instability in the financial markets, as a result of recession or otherwise, can cause volatility in the markets and may affect our ability to raise capital and reduce the amount of cash available to fund our operations. 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 negatively impact our access to liquidity needed for our business and impact our flexibility to react to changing economic and business conditions. 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.

Economic situations could have an adverse impact on our lenders, producers, key suppliers or other customers, causing them to fail to meet their obligations to us. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow and ability to make required debt service payments on our credit facility 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 2011 market prices for NGLs, natural gas and condensate, based upon NYMEX forward price curves as of January 11, 2011, are $1.14 per gallon, $4.54 per MMBTU and $92.77 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2011 by approximately $13.5 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations, and could cause operators of wells currently connected to our pipeline system or that we expect will be connected to our system to shut in their production until prices improve, thereby affecting the volume of gas we gather and process. Historically, the prices of natural gas, NGLs and crude oil have been subject to significant volatility in response to relatively minor changes in the supply and demand for these products, market uncertainty and a variety of additional factors beyond our control, including those we describe in The amount of cash we generate depends, in part, on factors beyond our control, above. Oil prices have traded in a range of $68.01 per barrel to $91.51 per barrel in 2010, while natural gas prices have traded in a range of $3.29 per MMBTU to $6.01 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 risk management strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of 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 flow.

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

Our operations expose us to fluctuations in commodity prices. We utilize derivative contracts related to the future price of crude oil, natural gas and NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. To the extent we protect our commodity 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.

We cannot predict at this time the outcome of the ongoing efforts by the Commodities Futures Trading Commission (CFTC) to implement the Dodd-Frank Act and to increase the regulation of over-the-counter derivatives including those related to energy commodities. The CFTC efforts are seeking, among other things, increased clearing of such derivatives through clearing organizations and the increased standardization of contracts, products, and collateral requirements. Such changes could negatively impact our ability to hedge our portfolio in an efficient, cost-effective manner by, among other things, increasing the cost of entering into derivative contracts and decreasing liquidity in the forward commodity markets.

Due to the accounting treatment of our derivative contracts, increases in prices for natural gas, crude oil and NGLs could result in non-cash balance sheet reductions.

With the objective of enhancing the predictability of future revenues, from time to time we enter into natural gas, natural gas liquids and crude oil derivative contracts. We account for these derivative contracts by applying the mark-to-market accounting treatment required for these derivative contracts. We could recognize incremental derivative liabilities between reporting periods resulting from increases or decreases in reference prices for natural gas, crude oil and NGLs, which could result in our recognizing a non-cash loss in our consolidated statements of operations and a consequent non-cash decrease in our Equity between reporting periods. Any such decrease could be substantial. In addition, we may be required to make cash payments upon the termination of any of these derivative contracts.

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, credit limits have been established 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.

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

We rely exclusively 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 crude oil. Due to our lack of asset-type diversification, a negative development in one of these businesses would 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 that are not committed to other systems, the level of drilling activity near our gathering systems and, in the Mid-Continent region, 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 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 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 does not accept the NGLs we sell to or transport on, 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, treat 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 does 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.

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

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. 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. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be reduced.

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

Our agreements with most of the producers with which our Mid-Continent operations 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 Midkiff/Benedum system, we do not have assured sources to provide us with new wells to connect to our Mid-Continent gathering systems. Failure to connect new wells to our Mid-Continent 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, will reduce our gross margin and cash flows.

Our Mid-Continent operations 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 2010, Apache, Inc., Bluestem Gas Marketing, Chesapeake Energy Corporation, COG Operating LLC, Endeavor Energy Resources LP, Pioneer, Prime Operating Company, Range Resources, Sandridge Exploration and Production, LLC and XTO Energy Inc. accounted for a significant amount of our Mid-Continent operations natural gas supply. If these producers reduce the volumes of natural gas that they supply to us, our gross margin and cash flows would be reduced unless we obtain comparable supplies of natural gas from other producers.

The curtailment of operations at, or closure of, any of our processing plants could harm our business.

If operations at any of our processing plants were to be curtailed, or closed, whether due to accident, natural catastrophe, environmental regulation 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 would be materially reduced.

We may face increased competition in the future in our Mid-Continent operations.

Our Mid-Continent operations face competition for well connections. Carrera Gas Company, Copano Energy, LLC, DCP Midstream, LLC, Enogex, LLC and ONEOK, Inc., operate competing gathering systems and processing plants in our Velma service area. DCP Midstream, Hiland Partners, Mustang Fuel Corporation, ONEOK Partners and SemGas, L P operate competing gathering systems and processing plants in our Chaney Dell service area. DCP Midstream, Southern Union Company, Targa Resources and West Texas Gas operate competing gathering systems and processing plants in our Midkiff/Benedum service area. Some of our competitors have greater financial and other resources than we do. If these companies become more active in our Mid-Continent service area, 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, process and treat will decrease, reducing our gross margin and cash flows.

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;

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- 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 of 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.

One of the ways we may grow our business is 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

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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 may construct facilities to capture anticipated future growth in production in a region in which growth does not materialize. Since we are not engaged in the exploration for, and development of, natural gas reserves, we often do not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, the estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could impair our results of operations and financial condition. In addition, our actual revenues from a project could materially differ from expectations as a result of the 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 will 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 to a much lesser extent, expansions of our gathering systems by bank credit facilities and the proceeds of public and private debt and equity offerings of our common units and preferred units of our operating partnership. If we are unable to access the capital markets, we may be unable to execute our strategy of growth through acquisitions.

Our debt levels and restrictions in our credit facility could limit our ability to fund operations, pay required debt service on our credit facility and make distributions to our unitholders.

We will need a portion of our cash flow to make principal and interest payments on our indebtedness, which will reduce the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders. 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 credit facility contains covenants limiting the ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to unitholders. Our credit facility also contains covenants requiring us to maintain certain financial ratios.

If we do not pay distributions on our common units with respect to any fiscal quarter, our unitholders are not entitled to receive distributions for such prior periods in the future.

Our distributions to our unitholders are not cumulative. Consequently, if we do not pay distributions on our common units with respect to any quarter, our unitholders are not entitled to receive such payments in the future.

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.

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 that any such regulation could increase our costs, decrease our gross margin and cash flows, or both.

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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 you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Since federal law generally leaves any economic regulation of natural gas gathering to the states, state and local regulations may also affect our business. Matters subject to such regulation include 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.

The cost of implementing integrity management program testing along certain segments of our pipeline should not have a material effect on our results of operations. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be necessary as a result of the testing program. Such costs could be substantial.

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.

The operations of our gathering systems, plant 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,

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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 pollutants 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 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 environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, it is possible that more stringent laws, regulations or enforcement policies could significantly increase our compliance costs, and the cost of any necessary remediation. We may not be able to recover some or any of these costs from insurance.

Our midstream natural gas operations may incur significant costs and liabilities resulting from new environmental regulations related to climate change.

Federal and state governments are considering and/or implementing measures to reduce emissions of greenhouse gases, primarily through the planned development of a greenhouse gas cap and trade program. As an alternative to the cap and trade program, the EPA may implement greenhouse gas reduction through traditional construction and operating permit programs. APL could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. In addition, our operations could face additional taxes 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.

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 which 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 that new regulations would increase our operating costs and, possibly, require us to obtain additional capital to pay for improvements or other compliance actions necessitated by those regulations.

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

Our operations are subject to all operating hazards and risks incidental to gathering 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 and farm equipment;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions;
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations; and
- acts of terrorism directed at our pipeline infrastructure, production facilities and surrounding properties.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for some of our insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, our gross margin and cash flows would be materially reduced.

Risks Related to Our Ownership Structure

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

AHD owns and controls our General Partner. We do not have any employees and, subsequent to the AHD Transaction, rely solely on employees of AHD, who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of AHD also own interests in us. Conflicts of interest may arise between AHD, 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 AHD who provide services to us may also devote time to the businesses of AHD 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.
- Our General Partner is allowed to take into account the interests of parties other than us, such as AHD, 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 AHD and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our gross margin and cash flows.

Our control of the Chaney Dell and Midkiff/Benedum systems is limited by provisions of the limited liability company operating agreements with Anadarko and, with respect to the Midkiff/Benedum system, the operation and expansion agreement with Pioneer.

The managing member of each of the limited liability companies which owns the interests in the Chaney Dell and Midkiff/Benedum 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 Midkiff/Benedum 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.

Tax Risks of 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 flow, likely causing a substantial reduction in the value of our units.

Current 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 any 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 that substantially all of our income will be generated in Oklahoma, Pennsylvania and Texas. 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.

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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.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

Following the November 9, 2010 announcement (the Announcement) that ATLS had entered into a definitive agreement to be acquired by Chevron Corporation (the Merger) and that AHD and we agreed to enter into separate transactions with ATLS relating to certain ATLS natural gas reserves and other assets and fee revenues, and our interest in Laurel Mountain (the Transactions), with each of the Transactions and the Merger to be cross-conditioned on the completion of the others, a purported class action was filed on November 15, 2010, in Delaware Chancery Court on behalf of a class of ATLS shareholders, Katsman v. ATLS, et al., C.A. No. 5990-VCL. The complaint named AHD and us and alleges that the ATLS directors violated their fiduciary duties in connection with the proposed Merger and that AHD, we and Chevron aided and abetted the alleged breaches of fiduciary duty, and requested, among other relief, injunctive relief and damages. This lawsuit was consolidated in Delaware Chancery with other class actions that have been filed against ATLS and its directors, among others. On December 28, 2010, the plaintiffs filed an amended complaint in which all claims against us and AHD were dropped.

Additionally, following the Announcement, a purported shareholder derivative case was filed on November 16, 2010, in the Western District of Pennsylvania federal court, Ussach v. ATLS, et al., C.A. No. 2:10-cv-1533. The complaint is asserted derivatively on behalf of us and names ATLS, the General Partner, and members of the Managing Board of the General Partner as defendants (Defendants) and alleges that Defendants have violated their fiduciary duties in connection with the proposed sale to ATLS of our interest in Laurel Mountain and that ATLS has been unjustly enriched. In the complaint, among other relief, the plaintiff requests damages and equitable and injunctive relief, as well as restitution and disgorgement from the individual defendants. On February 22, 2011, the plaintiff voluntarily dismissed its complaint without prejudice. We have not received an indication whether the plaintiff intends to reassert its claims in another forum. The defendants believe the claims are without merit.

ITEM 4: [REMOVED AND RESERVED]

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PART II

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

Our common units are listed on the New York Stock Exchange under the symbol APL. At the close of business on February 22, 2011, the closing price for the common units was $27.69 and there were 97 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, 2010 and 2009:

	High	Low	Distributions Declared
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
2009			
Fourth Quarter	$ 10.25	$ 6.55	$ 0.00
Third Quarter	8.31	5.44	0.00
Second Quarter	9.38	3.52	0.00
First Quarter	10.75	2.36	0.15

Our Cash Distribution Policy

Our partnership agreement requires that 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 of 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.

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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. In July 2007, our General Partner, the holder of all of our incentive distribution rights, agreed to allocate a portion of its incentive distribution rights back to us as defined in the IDR Adjustment Agreement. There were no General Partner incentive distributions declared for the years ended December 31, 2010 and 2009.

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

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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, 2010, 2009 and 2008 and at December 31, 2010 and 2009 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, 2007 and 2006 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 include our historical consolidated financial statements, which have been adjusted to reflect the following:

On September 16, 2010, we completed the sale of our Elk City and Sweetwater, Oklahoma natural gas gathering systems (collectively Elk City). We have retrospectively adjusted our prior period consolidated financial statements to reflect the amounts related to the operations of Elk City as discontinued operations.

We reclassified a portion of our historical income, within our consolidated statements of operations, to Transportation, Processing and Other Fees for fee-based revenues which were previously reported within Natural Gas and Liquids and Other income (loss), net . This reclassification was made in order to provide clarity between commodity-based and fee-based revenue.

We reclassified Equity income in joint venture and Gain (loss) on asset sales and other to line items separate from total revenue and other income (loss) net. Additionally, we reclassified unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition, long-lived asset impairment loss and goodwill impairment loss, net of associated non-controlling interest from reconciliation of EBITDA to reconciliation to adjusted EBITDA.

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	Years Ended December 31,				
	2010	2009(1)	2008(1)	2007(1)(2)	2006(1)
	(in thousands, except per unit data)				
Statements of operations data:					
Revenue:					
Natural gas and liquids	$ 890,048	$ 636,231	$ 1,078,714	$ 527,094	$ 174,221
Transportation, compression and other fees	41,093	59,075	87,442	50,695	31,263
Other income (loss), net	4,447	(22,701)	36,585	(99,272)	6,121
Total revenue and other income (loss), net	935,588	672,605	1,202,741	478,517	211,605
Costs and expenses:					
Natural gas and liquids	720,215	527,730	900,460	407,994	147,583
Plant operating	48,670	45,566	47,371	22,974	6,484
Transportation and compression	1,061	6,657	11,249	6,235	4,946
General and administrative(3)	34,021	37,280	(2,933)	59,600	19,127
Depreciation and amortization	74,897	75,684	71,764	34,453	9,495
Goodwill and other asset impairment loss		10,325	615,724		
Gain on early extinguishment of debt			(19,867)		
Interest	91,632	103,787	89,869	63,989	25,521
Total costs and expenses	970,496	807,029	1,713,637	595,245	213,156
Equity income in joint venture	4,920	4,043			
Gain (loss) on asset sales and other	(10,729)	108,947			
Income (loss) from continuing operations	(40,717)	(21,434)	(510,896)	(116,728)	(1,551)
Income (loss) from discontinued operations	321,155	84,148	(93,802)	(23,641)	35,334
Net income (loss)	280,438	62,714	(604,698)	(140,369)	33,783
(Income) loss attributable to non-controlling interests(4)	(4,738)	(3,176)	22,781	(3,940)	(118)
Preferred unit dividend effect				(3,756)	
Preferred unit imputed dividend cost			(505)	(2,494)	(1,898)
Preferred unit dividends	(780)	(900)	(1,769)		
Net income (loss) attributable to common limited partners and the General Partner	$ 274,920	$ 58,638	$ (584,191)	$ (150,559)	$ 31,767
Allocation of net income (loss) attributable to:					
Common Limited Partner interest:					
Continuing operations	$ (45,347)	$ (24,997)	$ (503,533)	$ (139,905)	$ (17,950)
Discontinued operations	315,021	82,457	(91,917)	(23,166)	34,508
	269,674	57,460	(595,450)	(163,071)	16,558
General Partner interest:					
Continuing operations	(888)	(513)	13,144	12,987	14,501
Discontinued operations	6,134	1,691	(1,885)	(475)	708
	5,246	1,178	11,259	12,512	15,209
Net income (loss) attributable to:					
Continuing operations	(46,235)	(25,510)	(490,389)	(126,918)	(3,449)
Discontinued operations	321,155	84,148	(93,802)	(23,641)	35,216
	$ 274,920	$ 58,638	$ (584,191)	$ (150,559)	$ 31,767

Net income (loss) attributable to common limited partners per unit:										
Basic:										
Continuing operations	$	(0.85)	$	(0.52)	$	(11.80)	$	(5.74)	$	(1.40)
Discontinued operations		5.92		1.71		(2.16)		(0.95)		2.68
	$	5.07	$	1.19	$	(13.96)	$	(6.69)	$	1.28
Diluted[(5)]:										
Continuing operations	$	(0.85)	$	(0.52)	$	(11.80)	$	(5.74)	$	(1.40)
Discontinued operations		5.92		1.71		(2.16)		(0.95)		2.68
	$	5.07	$	1.19	$	(13.96)	$	(6.69)	$	1.28

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	Years Ended December 31,				
	2010	2009[1]	2008[1]	2007[1][2]	2006[1]
	(in thousands, except operating data)				
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 1,341,002	$ 1,327,704	$ 1,415,517	$ 1,258,602	$ 204,362
Total assets	1,764,848	2,137,963	2,413,196	2,875,451	786,884
Total debt, including current portion	565,974	1,254,183	1,493,427	1,229,426	324,083
Total Equity	1,041,647	723,527	650,842	1,271,797	379,134
Cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 106,427	$ 55,853	$ (59,194)	$ 100,444	$ 60,920
Investing activities	594,753	241,123	(292,944)	(2,024,643)	(104,499)
Financing activities	(702,037)	(297,400)	341,242	1,935,059	27,028
Other financial data (unaudited):					
Gross margin from continuing operations [6]	$ 210,580	$ 163,677	$ 273,493	$ 167,525	$ 59,811
EBITDA [7]	454,902	258,846	(406,950)	(31,801)	82,321
Adjusted EBITDA [7]	209,799	174,808	322,515	183,496	87,140
Maintenance capital expenditures	$ 10,921	$ 3,750	$ 4,787	$ 6,383	$ 1,886
Expansion capital expenditures	35,715	106,524	176,869	40,268	24,498
Total capital expenditures	$ 46,636	$ 110,274	$ 181,656	$ 46,651	$ 26,384
Operating data (unaudited):					
Appalachia:					
Laurel Mountain system:					
Average throughput volume (MCFD)	109,480	96,975	85,348	68,715	61,892
Tennessee system					
Average throughput volume (MCFD)	8,740	7,907	1,951		
Mid-Continent:					
Velma system:					
Gathered gas volume (MCFD)	84,455	76,378	63,196	62,497	60,682
Processed gas volume (MCFD)	78,606	73,940	60,147	60,549	58,132
Residue Gas volume (MCFD)	64,138	58,350	47,497	47,234	45,466
NGL volume (BPD)	9,218	8,232	6,689	6,451	6,423
Condensate volume (BPD)	416	377	280	225	193
Chaney Dell system[8]:					
Gathered gas volume (MCFD)	228,684	270,703	276,715	259,270	
Processed gas volume (MCFD)	214,695	215,374	245,592	253,523	
Residue Gas volume (MCFD)	193,200	228,261	239,498	221,066	
NGL volume (BPD)	12,395	13,418	13,263	12,900	
Condensate volume (BPD)	697	824	791	572	
Midkiff/Benedum system[8]:					
Gathered gas volume (MCFD)	178,111	159,568	144,081	147,240	
Processed gas volume (MCFD)	163,475	149,656	135,496	141,568	
Residue Gas volume (MCFD)	105,982	101,788	92,019	94,281	
NGL volume (BPD)	26,678	21,261	19,538	20,618	
Condensate volume (BPD)	1,289	1,265	1,142	1,346	

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of Elk City.

(2) Includes our acquisition of control of a 100% interest in the Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided joint interest in the Midkiff/Benedum 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 Chaney Dell and Midkiff/Benedum systems represent 100% of its operating activity.

(3) Includes non-cash compensation (income) expense of $3.5 million, $0.7 million, ($34.0) million, $36.3 million, and $6.3 million for the years ended December 31, 2010, 2009, 2008, 2007, and 2006, respectively.

(4)

For the years ended December 31, 2010, 2009, 2008 and 2007, this represents Anadarko s non-controlling interest in the operating results of the Chaney Dell and Midkiff/Benedum systems, which we acquired on July 27, 2007.

(5) For the years ended December 31, 2008, 2007 and 2006, 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.

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(6) We define gross margin from continuing operations as natural gas and liquids revenue and transportation, compression and other fees less purchased product costs. Product costs include the cost of natural gas and NGLs that 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 hedge gain/(losses) 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 that 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,				
	2010	2009[1]	2008[1]	2007[1] [2]	2006[1]
			(in thousands)		
Revenue:					
Natural gas and liquids	$ 890,048	$ 636,231	$ 1,078,714	$ 527,094	$ 174,221
Transportation, compression and other fees	41,093	59,075	87,442	50,695	31,263
Total revenue for gross margin	931,141	695,306	1,166,156	577,789	205,484
Natural gas and liquids costs	(720,215)	(527,730)	(900,460)	(407,994)	(147,583)
Adjustments:					
Effect of prior period items[9]					1,090
Non-cash linefill loss (gain) [10]	(346)	(3,899)	7,797	(2,270)	820
Gross margin	$ 210,580	$ 163,677	$ 273,493	$ 167,525	$ 59,811

(7) 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 that is utilized within our financial covenants under our credit facility, with the exception that Adjusted EBITDA includes (i) EBITDA from the discontinued operations related to the sale of Elk City; (ii) the unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition, and (iii) 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):

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RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

	Years Ended December 31,				
	2010	2009[1]	2008[1]	2007[1] [2]	2006[1]
			(in thousands)		
Net income (loss)	$ 280,438	$ 62,714	$ (604,698)	$ (140,369)	$ 33,783
Adjustments:					
Effect of prior period items[9]					1,090
(Income) loss attributable to non-controlling interests from continuing operations[4]	(4,738)	(3,176)	22,781	(3,940)	
Interest expense	91,632	103,787	89,869	63,989	25,521
Other interest	604	443			
Depreciation and amortization	74,897	75,684	71,764	34,453	9,495
Discontinued operations interest expense, depreciation and amortization	12,069	19,394	13,334	14,066	12,432
EBITDA	$ 454,902	$ 258,846	$ (406,950)	$ (31,801)	$ 82,321
Adjustments:					
Equity income in joint venture	(4,920)	(4,043)			
Distributions from joint venture	11,066	4,310			
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum 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]	(301,373)	(162,518)			
Non-cash (gain) loss on derivatives	(10,166)	74,644	(113,640)	99,543	163
Non-recurring net cash derivative early termination expense[13]	22,401	2,260	102,146		
Premium expense on derivative instruments	21,123	9,693	3,736		
Non-cash compensation (income) expense	3,484	701	(34,010)	36,306	6,315
Non-cash line fill loss (gain) [10]	(346)	(3,899)	7,797	(2,270)	820
Other non-cash items[14]				1,414	
Discontinued operations adjustments[15]	13,628	(15,511)	178,383	69,881	(2,479)
Adjusted EBITDA	$ 209,799	$ 174,808	$ 322,515	$ 183,496	$ 87,140

(8) Volumetric data for the Chaney Dell and Midkiff/Benedum 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.

(9) During 2006, we identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during 2005, we recorded an adjustment to increase natural gas and liquids cost of goods sold.

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

(11) The acquisition of the Chaney Dell and Midkiff/Benedum 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, 2010, includes the gain on the sale of Elk City and expenses related to the pending 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 the Laurel Mountain joint venture 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 that were 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 Chaney Dell and Midkiff/Benedum 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 AHD and ATLS 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 our 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.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report.

General

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

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

Our Mid-Continent operations, as of December 31, 2010, own, have interests in and operate five natural gas processing plants with aggregate capacity of approximately 520 MMCFD. These facilities are connected to approximately 8,600 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gathers gas from wells and central delivery points to our natural gas processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are conducted principally through our 49% non-controlling ownership interest in the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which owns and operates approximately 1,000 miles of natural gas gathering systems in the Appalachian Basin located in Pennsylvania. We also own and operate approximately 70 miles of active natural gas gathering pipelines in Tennessee.

Laurel Mountain has natural gas gathering agreements with Atlas Energy Resources, LLC (Atlas Energy Resources), a wholly-owned subsidiary of Atlas Energy, Inc. (Atlas Energy, Inc. or ATLS), a formerly publicly-traded company, under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations).

Recent Events

On January 7, 2010, we executed amendments to warrants previously issued, along with our common units, in connection with a private placement to institutional investors that closed on August 20, 2009. The common units and warrants were issued and sold in a transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. 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 the issuance of 2,689,765 common units and net cash proceeds to us of approximately $15.3 million. 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 Term Loan and Credit Facility) and to fund the early termination of certain derivative agreements (see Item 8. Financial Statements and Supplementary Data Note 11).

On March 31, 2010, we and Atlas Pipeline Operating Partnership, L.P. amended our respective partnership agreements to temporarily waive the requirement that the General Partner make aggregate cash

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contributions of approximately $0.3 million, which was required in connection with our issuance of an aggregate of 2,689,765 of our common units upon the exercise of certain warrants in January 2010. The waiver remained in effect until the General Partner received aggregate distributions from us sufficient to fund the required capital contribution. During the waiver period, the aggregate ownership percentage attributable to the General Partner s general partner interest in us was reduced to 1.9%. Both amendments were approved by our conflicts committee and managing board, and were effective as of January 11, 2010. On November 30, 2010, we received a capital contribution from the General Partner of $0.3 million for the General Partner to increase its general partner interest in us back to 2.0%.

On June 15, 2010, our unitholders approved the terms of the 2010 Long Term Incentive Plan (2010 LTIP), which provides for the grant of options, phantom units, unit awards, unit appreciation rights and distribution equivalents. The total number of our common units that may be issued under the 2010 LTIP is 3,000,000 (see Item 8. Financial Statements and Supplementary Data Note 16).

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 ATLS for cash consideration of $1,000 per Class C Preferred Unit resulting in total proceeds of $8.0 million (see Preferred Units).

On September 1, 2010, we entered into an amendment to our credit facility agreement, which, among other things, revised the definition of Consolidated EBITDA to provide for the add-back of charges relating to premiums associated with hedging agreements and to exclude the net gains or losses attributable to a disposition of assets other than in the ordinary course of business (see Term Loan and Revolving Credit Facility).

On September 16, 2010, we completed the sale of our Elk City and Sweetwater, Oklahoma natural gas gathering systems, 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 million in cash, excluding working capital adjustments and transaction costs (See Item 8. Financial Statements and Supplementary Data Note 4). We utilized the proceeds from the sale to repay our senior secured term loan and a portion of our indebtedness under the revolving credit facility (see Term Loan and Revolving Credit Facility).

On November 8, 2010, we entered into a definitive agreement with ATLS and Atlas Energy Resources (the Laurel Mountain Sales Agreement), pursuant to which we agreed to sell our 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources for $403 million in cash, subject to certain closing adjustments. We intend to utilize the proceeds from the sale to repay our indebtedness, to fund future capital expenditures, and for general corporate purposes.

On November 15, 2010, Atlas Pipeline Holdings II, LLC (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, we redeemed our 15,000 units of Class B Preferred Units held by AHD for cash at the liquidation value of $1,000 per unit, or $15.0 million plus $0.2 million accrued dividends, in accordance with the terms of the amended preferred units certificate. There are no longer any Class B Preferred Units outstanding (See Preferred Units).

On November 22, 2010, we completed our consent solicitation to amend certain provisions of the Indenture governing our 8.125% Senior Notes, dated as of December 20, 2005, by and among us, Atlas Pipeline Finance Corporation, the Subsidiary Guarantors party thereto and U.S. Bank National Association. After receiving the requisite consents, we entered into a Supplemental Indenture to the Indenture, dated as of November 22, 2010, which amended and restated the definition of Permitted Investments under Section 1.01 of the Indenture to permit us, or our subsidiaries, to make capital contributions to Laurel Mountain through December 31, 2011.

On December 22, 2010, we entered into an amended and restated credit agreement (see Term Loan and Revolving Credit Facility) which, among other changes:

- set the maturity date of the revolving credit facility to December 22, 2015;
- reduced the revolving credit facility from $380.0 million to $350.0 million;
- eliminated the 2.0% per annum floor previously applied to adjusted LIBOR;
- removed restrictions on making investments in the Laurel Mountain joint venture if specified financial thresholds are not met;
- eliminated the requirements that we meet specified financial thresholds in order to be permitted to make distributions to our unitholders;
- eliminated the limits on annual capital expenditures if specified financial thresholds are not met; and
- adjusted the maximum Consolidated Funded Debt Ratio (leverage ratio) to 5.0 to 1.0; the maximum Consolidated Senior Secured Funded Debt Ratio (senior secured leverage ratio) to 3.0 to 1.0; and the minimum Interest Coverage Ratio to 2.5 to 1.0.

Subsequent Events

Laurel Mountain Sale

On February 17, 2011, we completed our sale to Atlas Energy Resources of our 49% non-controlling interest in Laurel Mountain (the Laurel Mountain Sale) for $413.5 million in cash, including adjustments based on certain 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 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.

AHD Transaction Agreement

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

Atlas Energy, Inc. Merger

Concurrently with the AHD Transactions, ATLS completed an agreement and plan of merger with Chevron Corporation, a Delaware corporation (Chevron), pursuant to which, among other things, ATLS became a wholly-owned subsidiary of Chevron (the Chevron Merger). Our common units and 12% cumulative Class C preferred units held directly by ATLS were acquired by Chevron as part of the Chevron Merger.

Significant Acquisitions

In July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering systems and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas.

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 they 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 that is gathered and processed;

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- 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 liquids 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 of 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. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas (See Item 8. Financial Statements and Supplementary Data Note 2 Revenue Recognition for further discussion of contractual revenue arrangements).

In our Appalachia segment, substantially all of the natural gas we gather via Laurel Mountain is for Atlas Energy Resources under contracts in which Laurel Mountain earns a fee equal to a percentage, generally 16%, of the gross sales price for natural gas, inclusive of the effects of financial and physical hedging, subject, in most cases, to a minimum of $0.35 per MCF, depending on the ownership of the well. The balance of the natural gas gathered by Laurel Mountain is for third-party operators generally under fixed-fee contracts.

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 that 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 that 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 recent 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

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changes on our future operations and, where appropriate, use various commodity-based derivative instruments such as natural gas, crude oil and NGL 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 and volumetric information related to our reportable segments for the periods indicated:

	Years Ended December 31,		
	2010	2009	2008
Pricing:			
Mid-Continent Weighted Average Prices:			
NGL price per gallon Conway hub	$ 0.92	$ 0.68	$ 1.19
NGL price per gallon Mt. Belvieu hub	1.03	0.77	1.29
Natural gas sales ($/Mcf):			
Velma	4.14	3.24	7.38
Chaney Dell	4.13	3.25	6.98
Midkiff/Benedum	4.10	3.35	7.44
Weighted Average	4.12	3.28	7.19
NGL sales ($/gallon):			
Velma	0.90	0.69	1.23
Chaney Dell	0.94	0.69	1.23
Midkiff/Benedum	1.02	0.83	1.27
Weighted Average	0.97	0.73	1.25
Condensate sales ($/barrel):			
Velma	78.28	59.80	100.65
Chaney Dell	72.67	55.07	97.29
Midkiff/Benedum	75.57	60.35	105.44
Weighted Average	75.08	58.21	100.85

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	Years Ended December 31, 2010	2009	2008
Operating data:			
Appalachia:			
Laurel Mountain system:			
Average throughput volumes (MCFD)	109,480	96,975	85,348
Tennessee system:			
Average throughput volumes (MCFD)	8,740	7,907	1,951
Mid-Continent:			
Velma system:			
Gathered gas volume (MCFD)	84,455	76,378	63,196
Processed gas volume (MCFD)	78,606	73,940	60,147
Residue Gas volume (MCFD)	64,138	58,350	47,497
NGL volume (BPD)	9,218	8,232	6,689
Condensate volume (BPD)	416	377	280
Chaney Dell system:			
Gathered gas volume (MCFD)	228,684	270,703	276,715
Processed gas volume (MCFD)	214,695	215,374	245,592
Residue Gas volume (MCFD)	193,200	228,261	239,498
NGL volume (BPD)	12,395	13,418	13,263
Condensate volume (BPD)	697	824	791
Midkiff/Benedum system:			
Gathered gas volume (MCFD)	178,111	159,568	144,081
Processed gas volume (MCFD)	163,475	149,656	135,496
Residue Gas volume (MCFD)	105,982	101,788	92,019
NGL volume (BPD)	26,678	21,261	19,538
Condensate volume (BPD)	1,289	1,265	1,142

Financial Presentation

On September 16, 2010, we completed the sale of Elk City (see Recent Events). As such, we have adjusted the prior period consolidated financial information presented to reflect the amounts related to the operations of Elk City as discontinued operations.

We have reclassified a portion of our historical income, within our consolidated statements of operations, to Transportation, Processing and Other Fees for fee-based revenues which were previously reported within Natural Gas and Liquids and Other income (loss), net . This reclassification was made in order to provide clarity between commodity-based and fee-based revenues.

We have reclassified Equity income in joint venture and Gain (loss) on asset sales and other to line items separate from Total revenue and other income (loss) net.

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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, 2010	2009(1)	Variance	Percent Variance
Revenue:				
Natural gas and liquids	$ 890,048	$ 636,231	$ 253,817	39.9%
Transportation, compression and other fee revenue	41,093	59,075	(17,982)	(30.4)%
Other income (loss), net	4,447	(22,701)	27,148	119.6%
Total Revenue and other income (loss), net	$ 935,588	$ 672,605	$ 262,983	39.1%

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

Natural gas and liquids revenue 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 revenue, while all other gains and losses related to derivative instruments are recorded within other income (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 Midkiff/Benedum 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 Chaney Dell system decreased for the year ended December 31, 2010 compared to the prior year due to a decreased number of well connects over the past year, 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 have 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.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives 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).

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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, 2010	2009(1)	Variance	Percent Variance
Costs and Expenses:				
Natural gas and liquids	$ 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	91,632	103,787	(12,155)	(11.7)%
Total Costs and Expenses	$ 970,496	$ 807,029	$ 163,467	20.3%

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

Natural gas and liquids cost of goods sold 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, partially offset by a $2.6 million higher amortization of deferred finance costs. 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 (see Recent Events). The increased amortization of deferred finance costs was due principally to accelerated amortization associated with the retirement of our term loan.

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, 2010	2009(1)	Variance	Percent Variance
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)%
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) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

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 pending sale of our 49% interest in Laurel Mountain in 2010 (See Subsequent Events).

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 Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The increase in net income of the Chaney Dell and Midkiff/Benedum 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 Petroleum Corporation s interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenue. The following table details the variances between the years ended 2009 and 2008 for revenues (in thousands):

	Years Ended December 31, 2009(1)	2008(1)	Variance	Percent Variance
Revenue:				
Natural gas and liquids	$ 636,231	$ 1,078,714	$ (442,483)	(41.0)%
Transportation, compression and other fee revenue	59,075	87,442	(28,367)	(32.4)%
Other income (loss), net	(22,701)	36,585	(59,286)	(162.1)%
Total Revenue and other income (loss), net	$ 672,605	$ 1,202,741	$ (530,136)	(44.1)%

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

Natural gas and liquids revenue for the year ended December 31, 2009 decreased primarily due to decreases in production revenue from the Chaney Dell system of $234.0 million, the Midkiff/Benedum system of $148.9 million, and the Velma system of $95.0 million, which were all impacted by lower average commodity prices and changes in volumes in comparison to the prior year.

Processed natural gas volume on the Chaney Dell system decreased for the year ended December 31, 2009 compared to the prior year partially due to shut-in wells as a result of lower gas prices. The Chaney Dell system increased its NGL production volume for the year ended December 31, 2009 compared to the prior year, representing an increase in production efficiency. The Midkiff/Benedum system s processed natural gas volume and NGL production volume for the year ended December 31, 2009 increased compared to the prior year, representing an increase in production efficiency partially due to the start-up of the new Consolidator plant. Processed natural gas volume and NGL production volume on the Velma system increased for the year ended December 31, 2009 from the prior year mainly due to the new gathering line from the Madill area.

Transportation, compression and other fee revenue for the year ended December 31, 2009 decreased primarily due to a $26.2 million decrease from the Appalachia system as a result of our May 2009 contribution of the majority of the system to Laurel Mountain, after which we recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations.

Other loss, net, including the impact of certain gains and losses recognized on derivatives for the year ended December 31, 2009, had an unfavorable movement due primarily to a $219.5 million unfavorable variance in non-cash mark-to-market adjustments on derivatives, offset by $101.6 million favorable 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) and an $55.2 million favorable movement in non-cash derivative gains related to the early termination of a portion of our derivative contracts.

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Costs and Expenses. The following table details the variances between the years ended 2009 and 2008 for costs and expenses (in thousands):

	Years Ended December 31, 2009(1)	2008(1)	Variance	Percent Variance
Costs and Expenses:				
Natural gas and liquids	$ 527,730	$ 900,460	$ (372,730)	(41.4)%
Plant operating	45,566	47,371	(1,805)	(3.8)%
Transportation and compression	6,657	11,249	(4,592)	(40.8)%
General and administrative	37,280	(2,933)	40,213	1371.1%
Depreciation and amortization	75,684	71,764	3,920	5.5%
Goodwill and other asset impairment loss	10,325	615,724	(605,399)	(98.3)%
Interest expense	103,787	89,869	13,918	15.5%
Gain on early extinguishment of debt		(19,867)	19,867	100.0%
Total Costs and Expenses	$ 807,029	$ 1,713,637	$ (906,608)	(52.9)%

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

Natural gas and liquids cost of goods sold for the year ended December 31, 2009 decreased primarily due to a decrease in average commodity prices and changes in volumes in comparison to the prior year as discussed above in revenues. Transportation and compression expenses decreased due to our contribution of the Appalachia system to Laurel Mountain.

General and administrative expense, including amounts reimbursed to affiliates, for the year ended December 31, 2009 increased primarily as a result of a $34.7 million increase in non-cash compensation expense primarily due to a $36.3 million net mark-to-market gain recognized during the year ended December 31, 2008 principally associated with the vesting of certain common unit awards that were based on the financial performance of certain assets during 2008. The mark-to-market gain was the result of a significant change in our common unit market price at December 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards. These common unit awards were issued during the year ended December 31, 2009.

Interest expense for the year ended December 31, 2009 increased mainly due to a $9.1 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, an $8.5 million increase in interest expense related to our additional senior notes issued during June 2008 (see Senior Notes) and a $2.1 million increase in the amortization of deferred finance costs due principally to accelerated amortization associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system, partially offset by a $5.9 million decrease in interest expense associated with our senior secured term loan primarily due to the repayment of $273.7 million of indebtedness since December 2008 (see Term Loan and Revolving Credit Facility) and lower unhedged interest rates.

Goodwill and other asset impairment loss for the year ended December 31, 2009 decreased compared to the prior year. The 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. The impairment loss for the year ended December 31, 2008 was due to an impairment charge to our goodwill from the reduction of our estimate of the fair value of goodwill in comparison to its carrying amount at December 31, 2008. The estimate of fair value of goodwill was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. There were no goodwill impairments for the year ended December 31, 2009.

Gain on early extinguishment of debt for the year ended December 31, 2008 resulted from our repurchase of approximately $60.0 million of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million of our 8.125% Senior Notes and approximately $27.0 million of our 8.75% Senior Notes. All of

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the Senior Notes repurchased have been retired and are not available for re-issue.

Other income items. The following table details the variances between the years ended 2009 and 2008 for other income items (in thousands):

	Years Ended December 31, 2009(1)	2008(1)	Variance	Percent Variance
Equity income in joint venture	$ 4,043	$	$ 4,043	100.0%
Gain on asset sales and other	108,947		108,947	100.0%
Income (loss) from discontinued operations	84,148	(93,802)	177,950	189.7%
(Income) loss attributable to non-controlling interests	(3,176)	22,781	(25,957)	(113.9)%

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

Equity income of $4.0 million for the year ended December 31, 2009 represents our ownership interest in the net income of Laurel Mountain for the period from its formation on May 31, 2009 through December 31, 2009.

Gain on asset sales and other of $108.9 million for the year ended December 31, 2009 represents the gain recognized on our contribution of a 51% ownership interest in our Appalachia natural gas gathering system to Laurel Mountain.

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system we sold on May 4, 2009 and Elk City we sold on September 16, 2010 (see Recent Events). For the year ended December 31, 2009, income from discontinued operations increased due to a $114.3 million loss on Elk City operations in the prior year, primarily due to a $123.6 million dollar loss related to the early termination of certain derivatives in the prior year, and a $51.1 million gain recognized on the sale of the NOARK system in 2009.

Income attributable to non-controlling interests for the year ended December 31, 2009 changed as a result of higher net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish APL s acquisition of control of the respective systems. The increase in net income of the Chaney Dell and Midkiff/Benedum joint ventures was principally due to the goodwill impairment charge in 2008 of $613.4 million for the goodwill originally recognized upon acquisition of these systems. The non-controlling interest expense represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our 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, 2010, we had $70.0 million of outstanding borrowings under our $350.0 million senior secured credit facility and $3.2 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with $276.8 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Revolving Credit Facility). We were in compliance with the credit facility s covenants at December 31, 2010. At December 31, 2010, we had a working capital deficit of $36.6 million compared with a $30.6 million working capital deficit at December 31, 2009. We believe that 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 flow. 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 flow from operations and our 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 the extent required and on acceptable terms.

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 Variance
Net cash provided by (used in):				
Operating activities	$ 106,427	$ 55,853	$ 50,574	90.6%
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.

Cash Flows Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The following table details the variances between the years ended 2009 and 2008 for cash flows (in thousands):

	Years Ended December 31,			
	2009	**2008**	**Variance**	**Percent Variance**
Net cash provided by (used in):				
Operating activities	$ 55,853	$ (59,194)	$ 115,047	194.4%
Investing activities	241,123	(292,944)	534,067	182.3%
Financing activities	(297,400)	341,242	(638,642)	(187.2)%
Net change in cash and cash equivalents	$ (424)	$ (10,896)	$ 10,472	96.1%

Net cash provided by operating activities for the year ended December 31, 2009 increased due to a $265.2 million favorable movement in net earnings from continuing operations excluding non-cash charges, partially offset by a $127.7 million decrease in cash provided by discontinued operations and a $22.5 million decrease in cash flows from working capital changes. The increase in net earnings from continuing operations excluding non-cash charges was principally due to a $161.7 million decrease of net cash derivative expense, including expenses related to the early termination of a portion of our derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 11).

Net cash provided by investing activities for the year ended December 31, 2009 increased principally due to a $409.2 million increase in cash provided by discontinued operations, the net proceeds of $89.5 million received from the sale of our Appalachia system assets and a $71.4 million decrease in capital expenditures, partially offset by a 2008 receipt of a $30.2 million cash reimbursement for state sales tax paid on our 2007 transaction to acquire the Chaney Dell and Midkiff/Benedum systems and a 2008 period receipt of $1.3 million in connection with a post-closing purchase price adjustment of our 2007 acquisition of the Chaney Dell and Midkiff/Benedum systems (see further discussion of capital expenditures under Capital Requirements).

Net cash used in financing activities for the year ended December 31, 2009 decreased principally due to $244.9 million of net proceeds from the issuance of 8.75% Senior Notes in 2008 (see Senior Notes), a decrease of $240.9 million of net proceeds from the issuance of our common units, and a $173.0 million net decrease in borrowings under our revolving credit facility.

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 of 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,		
	2010	2009(1)	2008(1)
Maintenance capital expenditures	$ 10,921	$ 3,750	$ 4,787
Expansion capital expenditures	35,715	106,524	176,869
Total	$ 46,636	110,274	$ 181,656

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

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 the prior year, compounded by a reduction of well connects in the current period. 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. As of December 31, 2010, we have approved expenditures of approximately $32.4 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Expansion capital expenditures decreased for the year ended December 31, 2009 due principally to the construction of the Madill to Velma pipeline during the year ended December 31, 2008 and decreases in capital expenditures related to the sale of the 51% ownership interest in the Appalachia system. The decrease in maintenance capital expenditures for the year ended December 31, 2009, compared with the prior year, was due to fluctuations in the timing of 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 of 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. During July 2007, our General Partner, holder of all of our incentive distribution rights, 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. No incentive distributions were declared for the years ended December 31, 2010 and 2009.

Off Balance Sheet Arrangements

As of December 31, 2010, our off balance sheet arrangements are limited to our letters of credit, issued under the provisions of our revolving credit facility, totaling $3.2 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety and (iii) counterparty support.

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2010 (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	$ 568,529	$	$	$ 345,479	$ 223,050
Interest on total debt(1)	270,608	44,539	89,078	89,012	47,979
Derivative-based obligations	10,172	4,564	5,608		
Capital leases	838	258	516	64	
Operating leases	10,156	4,737	5,295	124	
Total contractual cash obligations	$ 860,303	$ 54,098	$ 100,497	$ 434,679	$ 271,029

(1) Based on the interest rates of our respective debt components as of December 31, 2010.

		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	$ 3,217	$ 3,217	$	$	$
Total commercial commitments	$ 3,217	$ 3,217	$	$	$

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 Term Loan and 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 of 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 Term Loan and Credit Facility) and to fund the early termination of certain derivative agreements. See Item 8. Financial Statements and Supplementary Data Note 11 .

In June 2008, we sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, we sold 1,112,000 common units to ATLS and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. We also received a capital contribution from the General Partner of $5.4 million for the General Partner to maintain its 2.0% general partner interest in us. We utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements.

Preferred Units

Class A Preferred Units

In December 2008, we redeemed 10,000 of the then-outstanding 40,000 cumulative convertible preferred units (Class A Preferred Units), owned by Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for $10.0 million in cash under the terms of the agreement. The redemption was classified as a reduction of Class A Preferred Equity within Equity on our consolidated balance sheets.

In January 2009, we and Sunlight Capital amended certain terms of the Class A Preferred Units. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, and (b) required that we issue Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 (see Senior Notes) to redeem 10,000 Class A Preferred Units. Our management 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, we 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 that is presented as a reduction of long-term debt on our consolidated balance sheets. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense in our consolidated statements of operations over the term of the notes based upon the effective interest rate method.

In April 2009, we redeemed 10,000 of the Class A Preferred Units for cash at the liquidation value of $1,000 per unit, or $10.0 million and we converted 5,000 of the Class A Preferred Units into 1,465,653 common units, reclassifying $5.0 million from Class A preferred limited partner equity to common limited partner equity within Equity. In May 2009, we 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 our redemption. There are no longer any Class A Preferred Units outstanding.

Class B Preferred Units

In December 2008, we sold 10,000 12.0% cumulative convertible Class B preferred units of limited partner interests (the Class B Preferred Units) to AHD 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).

In March 2009, AHD purchased an additional 5,000 Class B Preferred Units at Face Value. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. Additionally, in March 2009, we and AHD 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 our common units. The cumulative sale of the Class B Preferred Units to AHD was exempt from the registration requirements of the Securities Act of 1933.

In November 2010, we redeemed the 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 accrued dividends representing the quarterly dividend on the 15,000 Class B Preferred Units prior to our redemption. There are no longer any Class B Preferred Units outstanding. See Item 8. Financial Statements and Supplementary Data Note 6 .

Class C 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 ATLS for cash consideration of $1,000 per Class C Preferred

Unit, for total proceeds of $8.0 million. We used the proceeds from the sale of the Class C Preferred Units for general partnership purposes.

The sale of the Class C Preferred Units to ATLS was exempt from the registration requirements of the Securities Act of 1933 by reason of Section 4(2) thereunder and pursuant to SEC staff positions. The Class C Preferred Units receive 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 will be the same as the record date for determination of common unit holders entitled to receive quarterly distributions. We have the right to redeem some or all of the Class C Preferred Units (but not less than 2,500 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. See Item 8. Financial Statements and Supplementary Data Note 6 . The Class C Preferred Units are reflected on our consolidated balance sheets as Class C preferred equity within Equity.

Term Loan and Revolving Credit Facility

At December 31, 2010, we had a senior secured credit facility with a syndicate of banks which consisted of a $350.0 million revolving credit facility which matures in December 2015. The term loan, which was a part of the credit facility, was paid in full in September 2010. Borrowings under the revolving credit facility bear interest, at our option, at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2010 was 3.8%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $3.2 million was outstanding at December 31, 2010. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum 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 restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its 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 credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement. We are in compliance with these covenants as of December 31, 2010.

The events which 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, 2010, we were in compliance with all covenants under the credit facility.

Senior Notes

At December 31, 2010, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $3.4 million of unamortized discount as of December 31, 2010. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our credit facility.

In December 2008, we repurchased approximately $60.0 million in face amount of Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of 8.125% Senior Notes and approximately $27.0 million in face amount of 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

In January 2009, we issued Sunlight Capital $15.0 million of our 8.125% Senior Notes to redeem 10,000 Class A Preferred Units (see Preferred Units). Our management 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, we recognized a $5.0 million discount on the issuance of the Senior Notes, which is presented as a reduction of long-term debt on our consolidated balance sheets. The discount recognized upon issuance of the Senior Notes will be amortized to interest expense in our consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We are in compliance with these covenants as of December 31, 2010.

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 allows us to make capital contributions to Laurel Mountain Midstream, LLC through 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 that 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 that 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 that 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 that 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. Related to greenhouse gas emissions, cap and trade programs or greenhouse gas permitting programs are being considered by Congress. Depending on the program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. In addition, we could face additional taxes and higher costs of doing business. Although we would not be impacted to a

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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. However, we are currently unable to assess the timing and effect of the pending legislation.

We continue to monitor regulatory and legislative activities regarding greenhouse gas production, detection, reporting and mitigation issues. We recognize that greenhouse gas issues continue to be very dynamic topics of discussion within the scientific, business and political communities, and we are committed to staying abreast of developing rules and mandates that will affect our operations and business activities. We participate within industry organizations in order to contribute to consolidated initiatives that are continuously monitoring, addressing and contributing to these greenhouse gas issues, both during and following their development.

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 that 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 that 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. While inflation did not have a material impact on our results of operations for the years ended December 31, 2010, 2009 and 2008, the energy sector realized increased costs during 2008, caused by the demand in energy equipment and services due to the increase in commodity prices. Commodity prices have decreased from their highs in 2008 and the related costs have also declined. While we anticipate that inflation will 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 that 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 that are 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 critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of properties, plants and equipment, less estimated salvage value, is generally depreciated on a straight-line basis over the estimated useful lives of the assets. Useful lives are based on historical experience and are adjusted when changes in planned use, technological advances or other factors indicate that a different life would be more appropriate. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively.

Long-lived assets other than goodwill and intangibles with infinite lives are reviewed for impairment

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whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset other than goodwill and intangibles with infinite lives is considered to be impaired when the undiscounted net cash flows expected to be generated by the asset are less than its carrying amount. Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under Forward Looking Statements elsewhere in this document.

As discussed below, we recognized an impairment of goodwill at December 31, 2008. We believe this impairment of goodwill was an event that warranted assessment of our long-lived assets for possible impairment. During the year ended December 31, 2009, we 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, we recognized an impairment charge within goodwill and other asset impairments on our consolidated statements of operations of approximately $10.3 million for the year ended December 31, 2009. There were no long-lived asset impairments recognized by us during the years ended December 31, 2010 and 2008.

Goodwill and Intangibles with Infinite Lives. Goodwill and intangibles with infinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized if the carrying value of an entity s reporting units exceeds its estimated fair value.

As a result of our impairment evaluation at December 31, 2008, we recognized a $615.7 million non-cash impairment charge within our consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in our estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. Our estimated fair value of the reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. There were no goodwill impairments recognized by us during the years ended December 31, 2010 and 2009. See Goodwill in Item 8: Financial Statements and Supplementary Data Note 2 for information regarding our impairment of goodwill and other assets.

Fair Value of Financial Instruments

We use 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 our 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 assumption 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.

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts (see Item 8. Financial Statements and Supplementary Data Note 12). At December 31, 2010, all of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and NGL options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Valuations for our 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 our NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3.

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 of our market risk sensitive instruments were entered into for purposes other than trading.

General

All of 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 periodical 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, 2010. 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 currently participating in our revolving credit facility. We may choose to do business with counterparties outside of our credit facility in the future. 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, 2010, we had a $350.0 million senior secured revolving credit facility with $70.0 million outstanding. Borrowings under the revolving credit facility bear interest at our option at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for the revolving credit facility borrowings was 3.8% at December 31, 2010. At December 31, 2010, we had no interest rate derivative contracts. Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately $3.5 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 or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. See Item 8. Financial Statements and Supplementary Data Note 11 for further discussion of our derivative instruments. Average estimated 2011 market prices for NGLs, natural gas and condensate, based upon New York Mercantile Exchange (NYMEX) forward price curves as of January 11, 2011, are $1.14 per gallon, $4.54 per million BTU and $92.77 per barrel. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2011 by approximately $13.5 million.

During the years ended December 31, 2010, 2009 and 2008, we made net payments of $25.3 million, $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through 2012. During the years ended December 31, 2010, 2009 and 2008, we recognized the following derivative activity related to the early termination of these derivative instruments within our consolidated statements of operations (in thousands):

Early termination of derivative contracts

	For the Years Ended December 31,		
	2010	2009(1)	2008(1)
Cash paid for early termination	$ (25,315)	$ (5,000)	$ (273,987)
Deferred recognition of loss on early termination(2)			76,345
Equity applied to prior period early termination	(8,421)		
Total realized loss at early termination(3)	$ (33,736)	$ (5,000)	$ (197,642)
Net cash derivative expense included within natural gas and liquids revenue	$ 12,198	$	$ 1,762
Net cash derivative expense included within other loss, net	(34,599)	(2,260)	(103,909)
Net cash derivative expense included within discontinued operations	(11,335)	(2,740)	(95,495)
Total realized loss at early termination(3)	(33,736)	(5,000)	(197,642)
Recognition of deferred hedge loss from prior periods included within natural gas and liquids revenue(4)	(25,726)	(43,112)	(19,764)
Recognition of deferred hedge gain (loss) from prior periods included within other income (loss), net(4)	35,342	31,488	(23,716)
Recognition of deferred hedge gain (loss) from prior periods included within discontinued operations(4)	4,137	(11,994)	(28,127)
Total realized loss from early termination recognized in current period(3)	$ (19,983)	$ (28,618)	$ (269,249)

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City.

(2) Deferred recognition based upon effective portion of hedges deferred to other comprehensive income, plus theoretical premium related to unwound options which had previously been purchased or sold as part of costless collars.

(3) Realized gain (loss) represents the gain/loss recognized when the derivative contract is settled. A portion of realized gain (loss) recognized in other income (loss), net is a reclassification of unrealized gain (loss) previously recognized as a factor of recording the changes in the fair value of the derivatives prior to settlement.

(4) Non-cash recognition of deferred hedge gain (loss) includes (i) theoretical premiums related to calls sold in conjunction with puts purchased in costless collars in which the puts were sold as part of the equity unwinds in 2008 and (ii) the effective portion of hedges deferred to other comprehensive income.

In addition, we will recognize a total of $5.1 million of net income relating to derivative contracts terminated in 2008. This income will be recognized in our consolidated statements of operations during the periods for which the hedged physical transactions are forecasted to be settled, with $2.8 million and $2.3 million of net income to be recognized during the years ending December 31, 2011 and 2012, respectively.

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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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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 25, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 25, 2011

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 164	$ 1,021
Accounts receivable	99,759	80,019
Current portion of derivative asset		998
Prepaid expenses and other	15,118	13,360
Current assets of discontinued operations		22,746
Total current assets	115,041	118,144
Property, plant and equipment, net	1,341,002	1,327,704
Intangible assets, net	126,379	149,481
Investment in joint venture	153,358	132,990
Long-term portion of derivative asset		361
Other assets, net	29,068	30,253
Long-term assets of discontinued operations		379,030
Total assets	$ 1,764,848	$ 2,137,963
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 210	$
Accounts payable affiliates	12,280	2,043
Accounts payable	29,382	19,556
Accrued liabilities	30,013	13,320
Accrued interest payable	1,921	9,652
Current portion of derivative liability	4,564	33,547
Accrued producer liabilities	72,996	57,430
Distribution payable	240	
Current liabilities of discontinued operations		13,181
Total current liabilities	151,606	148,729
Long-term portion of derivative liability	5,608	11,126
Long-term debt, less current portion	565,764	1,254,183
Other long-term liability	223	398
Commitments and contingencies		
Equity:		
General Partner s interest	20,066	15,853
Class B preferred limited partner s interest		14,955
Class C preferred limited partner s interest	8,000	
Common limited partners interests	1,057,342	787,834
Investment in Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)		(15,000)
Accumulated other comprehensive loss	(11,224)	(49,190)
Total partners capital	1,074,184	754,452
Non-controlling interests	(32,537)	(30,925)

Total equity	1,041,647	723,527
Total liabilities and equity	$ 1,764,848	$ 2,137,963

See accompanying notes to consolidated financial statements

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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, 2010	2009	2008
Revenue:			
Natural gas and liquids	$ 890,048	$ 636,231	$ 1,078,714
Transportation, compression and other fees third parties	40,474	41,539	44,149
Transportation, compression and other fees affiliates	619	17,536	43,293
Other income (loss), net	4,447	(22,701)	36,585
Total revenue and other income (loss), net	935,588	672,605	1,202,741
Costs and expenses:			
Natural gas and liquids	720,215	527,730	900,460
Plant operating	48,670	45,566	47,371
Transportation and compression	1,061	6,657	11,249
General and administrative	32,521	34,549	(4,420)
Compensation reimbursement affiliates	1,500	2,731	1,487
Depreciation and amortization	74,897	75,684	71,764
Goodwill and other asset impairment loss		10,325	615,724
Interest	91,632	103,787	89,869
Gain on early extinguishment of debt			(19,867)
Total costs and expenses	970,496	807,029	1,713,637
Equity income in joint venture	4,920	4,043	
Gain (loss) on asset sales and other	(10,729)	108,947	
Loss from continuing operations	(40,717)	(21,434)	(510,896)
Discontinued operations:			
Gain on sale of discontinued operations	312,102	53,571	
Earnings (loss) of discontinued operations	9,053	30,577	(93,802)
Income (loss) from discontinued operations	321,155	84,148	(93,802)
Net income (loss)	280,438	62,714	(604,698)
(Income) loss attributable to non-controlling interests	(4,738)	(3,176)	22,781
Preferred unit dividends	(780)	(900)	(1,769)
Preferred unit imputed dividend cost			(505)
Net income (loss) attributable to common limited partners and the General Partner	$ 274,920	$ 58,638	$ (584,191)

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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, 2010	2009	2008
Allocation of net income (loss) attributable to:			
Common limited partners interest:			
Continuing operations	$ (45,347)	$ (24,997)	$ (503,533)
Discontinued operations	315,021	82,457	(91,917)
	269,674	57,460	(595,450)
General Partner s interest:			
Continuing operations	(888)	(513)	13,144
Discontinued operations	6,134	1,691	(1,885)
	5,246	1,178	11,259
Net income (loss) attributable to:			
Continuing operations	(46,235)	(25,510)	(490,389)
Discontinued operations	321,155	84,148	(93,802)
	$ 274,920	$ 58,638	$ (584,191)
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ (0.85)	$ (0.52)	$ (11.80)
Discontinued operations	5.92	1.71	(2.16)
	$ 5.07	$ 1.19	$ (13.96)
Diluted:			
Continuing operations	$ (0.85)	$ (0.52)	$ (11.80)
Discontinued operations	5.92	1.71	(2.16)
	$ 5.07	$ 1.19	$ (13.96)
Weighted average common limited partner units outstanding:			
Basic	53,166	48,299	42,513
Diluted	53,166	48,299	42,513

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2010	**2009**	**2008**
Net income (loss)	$ 280,438	$ 62,714	$ (604,698)
(Income) loss attributable to non-controlling interests	(4,738)	(3,176)	22,781
Preferred unit dividends	(780)	(900)	(1,769)
Preferred unit imputed dividend cost			(505)
Net income (loss) attributable to common limited partners and the General Partner	274,920	58,638	(584,191)
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges		(2,268)	(97,435)
Add: adjustment for realized losses reclassified to net income (loss)	37,966	58,022	54,541
Total other comprehensive income (loss)	37,966	55,754	(42,894)
Comprehensive income (loss)	$ 312,886	$ 114,392	$ (627,085)

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

	Number of Limited Partner Units										Class B Preferred Units of Atlas Pipeline Holdings II, LLC		
	Class A Preferred	Class B Preferred	Class C Preferred	Common	Class A Preferred Limited Partner	Class B Preferred Limited Partner	Class C Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive (Loss)		Non-controlling Interest	Total
Balance at December 31, 2007	40,000			38,758,581	$ 37,076	$	$	$ 1,269,521	$ 29,413	$ (62,050)	$	$ (2,163)	$ 1,271,797
Issuance of units		10,000		7,140,000		10,000		256,928					266,928
Redemption of Class A cumulative convertible preferred limited partner units	(10,000)				(10,053)								(10,053)
General Partner capital contribution									5,452				5,452
Distribution paid					(1,437)			(161,248)	(31,602)			(7,393)	(201,680)
Unissued common units under incentive plans								(34,010)					(34,010)
Issuance of units under incentive plans				56,227									
Other comprehensive loss										(42,894)			(42,894)
Net income (loss)					2,267	7		(595,449)	11,258			(22,781)	(604,698)
Balance at December 31, 2008	30,000	10,000		45,954,808	27,853	10,007		735,742	14,521	(104,944)		(32,337)	650,842
Issuance of units		5,000		2,689,765		4,955		16,074					21,029
Redemption/Conversion of Class A cumulative convertible preferred limited partner units	(30,000)			1,465,653	(27,528)			2,528					(25,000)
General Partner capital contribution									658				658
Distributions paid					(775)	(457)		(24,671)	(505)			(1,764)	(28,172)
Unissued common units under incentive plans								702					702
Issuance of common units under incentive plans				406,877									
Purchase of Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)											(15,000)		(15,000)
Other comprehensive income										55,754			55,754
Net income					450	450		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

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

	Number of Limited Partner Units										Class B Preferred Units of Atlas Pipeline Holdings II, LLC		
	Class A Preferred	Class B Preferred	Class C Preferred	Common	Class A Preferred Limited Partner	Class B Preferred Limited Partner	Class C Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive (Loss)		Non-controlling Interest	Total
Balance at December 31, 2009		15,000		50,517,103		14,955		787,834	15,853	(49,190)	(15,000)	(30,925)	723,527
Issuance of units			8,000	2,689,765			8,000	15,319					23,319
Redemption of Class B cumulative preferred limited partner units		(15,000)				(14,955)		(45)					(15,000)
Redemption of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC (reported as treasury units)											15,000		15,000
Distributions paid						(2,927)	(240)	(18,834)	(363)		2,627	(6,350)	(26,087)
Distribution payable							(240)						(240)
General partner capital contribution									(670)				(670)
Issuance of units under incentive plans				151,584				156					156
Repurchase and retirement of common limited partner units				(20,442)				(246)					(246)
Unissued units under incentive plans								3,484					3,484
Other comprehensive income										37,966			37,966
Net income						2,927	480	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

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,		
	2010	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 280,438	$ 62,714	$ (604,698)
Less: Income (loss) from discontinued operations	321,155	84,148	(93,802)
Net loss from continuing operations	(40,717)	(21,434)	(510,896)
Adjustments to reconcile net loss from continuing operations to net cash provided by (used in) operating activities:			
Depreciation and amortization	74,897	75,684	71,764
Goodwill and other asset impairment loss		10,325	615,724
Gain on early extinguishment of debt			(19,867)
Equity income in joint venture	(4,920)	(4,043)	
Distributions received from joint venture	11,066	4,310	
(Gain) loss on asset sales	2,229	(108,947)	
Non-cash compensation expense (income)	3,484	702	(34,010)
Amortization of deferred finance costs	10,545	8,016	5,946
Other non-cash			(7,393)
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable and prepaid expenses and other	(21,498)	(2,686)	35,559
Accounts payable and accrued liabilities	32,906	1,197	(14,685)
Accounts payable and accounts receivable affiliates	10,237	2,580	2,700
Derivative accounts payable and accounts receivable	4,824	48,007	(373,833)
Net cash provided by (used in) continuing operating activities	83,053	13,711	(228,991)
Net cash provided by discontinued operating activities	23,374	42,142	169,797
Net cash provided by (used in) operating activities	106,427	55,853	(59,194)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash received related to acquisitions			31,429
Capital contribution to joint venture	(26,514)	(1,680)	
Capital expenditures	(45,752)	(110,274)	(181,656)
Net proceeds (expenditures) related to asset sales	(2,229)	89,472	
Other	56	(1,782)	1,125
Net cash used in continuing investing activities	(74,439)	(24,264)	(149,102)
Net cash provided by (used in) discontinued investing activities	669,192	265,387	(143,842)
Net cash provided by (used in) investing activities	594,753	241,123	(292,944)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	482,000	694,000	787,400
Repayments under credit facility	(738,000)	(670,000)	(590,400)
Net proceeds from issuance of debt			244,854
Repayment of debt	(433,505)	(273,675)	(162,938)
Principal payments on capital lease	(142)		
Net proceeds from issuance of common limited partner units	15,475	16,074	256,928

Net proceeds from issuance of preferred limited partner units	8,000	4,955	10,000
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		
Redemption of preferred units	(15,000)	(15,000)	(10,053)
General partner capital contributions	331	658	5,452
Net distributions paid to non-controlling interests	(6,350)	(1,764)	
Distributions paid to common limited partners, the General Partner and preferred limited partners	(19,737)	(26,349)	(193,741)
Other	(10,109)	(11,299)	(6,260)
Net cash provided by (used in) financing activities	(702,037)	(297,400)	341,242
Net change in cash and cash equivalents	(857)	(424)	(10,896)
Cash and cash equivalents, beginning of year	1,021	1,445	12,341
Cash and cash equivalents, end of year	$ 164	$ 1,021	$ 1,445

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 NATURE OF OPERATIONS

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. 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, 2010, Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owned a 2.0% general partner interest in the consolidated operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. The General Partner also owned 5,754,253 common units in the Partnership. At December 31, 2010, the Partnership had 53,338,010 common units outstanding, including the 5,754,253 common units held by the General Partner, plus 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units held by Atlas Energy, Inc. (Atlas Energy, Inc. or ATLS), a formerly publicly-traded company (see Note 6).

On March 31, 2010, the Partnership s limited partnership agreement was amended to provide a temporary waiver of a capital contribution required for the General Partner to maintain its 2.0% general partner interest in the Partnership, relative to the January 2010 issuance of common units for warrants exercised. The General Partner was not required to make such capital contribution until it had received aggregate distributions from the Partnership, sufficient to fund the required capital contribution. On November 30, 2010, the General Partner made the required capital contribution, terminating the waiver period. During the waiver period the General Partner s general partner interest was reduced by approximately 0.1% to 1.9% (see Note 5).

The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P., formerly known as Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). At December 31, 2010, ATLS owned a 64.0% ownership interest in AHD s common units, and 1,112,000 of the Partnership s common units, representing a 2.1% ownership interest in the Partnership, along with 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units (see Note 6).

On February 17, 2011, AHD completed a transaction agreement with ATLS and Atlas Energy Resources, LLC (Atlas Energy Resources) pursuant to which, among other things (1) AHD acquired certain assets from ATLS (the AHD Asset Acquisition); (2) ATLS contributed AHD s general partner, Atlas Pipeline Holdings GP to AHD, so that Atlas Pipeline Holdings GP became AHD s wholly-owned subsidiary; and (3) ATLS distributed to its stockholders all AHD s common units that it held, including the newly issued common units that it received in the AHD Asset Acquisition.

The majority of the natural gas that the Partnership and its affiliates, including Laurel Mountain Midstream, LLC (Laurel Mountain), gather in Appalachia is derived from wells operated by Atlas Energy Resources and its subsidiaries. Laurel Mountain, which was formed in May 2009, is a joint venture between the Partnership and The Williams Companies, Inc. (NYSE: WMB) (Williams) in which the Partnership has a 49% non-controlling ownership interest and Williams holds the remaining 51% ownership interest (see Note 3).

Concurrently with the AHD Asset Acquisition, the Partnership completed its sale to Atlas Energy Resources of its 49% non-controlling interest in Laurel Mountain (the Laurel Mountain Sale) for $413.5

million in cash, which included adjustments based on capital contributions the Partnership made to and distributions it received from Laurel Mountain after January 1, 2011 (See Note 21).

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-K from the amounts previously presented to reflect the following items:

The Partnership reclassified a portion of its historical income, within its consolidated statements of operations, to Transportation, Processing and Other Fees for fee-based revenues which were previously reported within Natural Gas and Liquids and Other income (loss), net . This reclassification was made in order to provide clarity between commodity-based and fee-based revenue.

The Partnership reclassified Equity income in joint venture and Gain (loss) on asset sales and other to line items separate from Total revenue and other income (loss) net .

On September 16, 2010, the Partnership completed the sale of its Elk City and Sweetwater, Oklahoma natural gas gathering systems (collectively Elk City) (see Note 4). The Partnership has retrospectively adjusted its prior period consolidated financial statements to reflect the amounts related to the operations of Elk City as discontinued operations.

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 Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided interest in the Midkiff/Benedum 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 Midkiff/Benedum joint venture has a 72.8% undivided joint venture interest in the Midkiff/Benedum system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) (Pioneer). Due to the ownership of the Midkiff/Benedum system being in the form of an undivided interest, the Midkiff/Benedum joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the Midkiff/Benedum system.

Equity Method Investments

The Partnership s consolidated financial statements include its 49% non-controlling ownership interest in Laurel Mountain, a joint venture which owns and operates the Partnership s former Appalachia Basin natural gas gathering systems, excluding the Partnership s Tennessee operations. The Partnership accounts for its investment in the joint venture under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint venture s 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 that 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.

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, 2010 and 2009, 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. During the year ended December 31, 2010, the Partnership entered into capital lease arrangements having obligations of $0.9 million at inception. Leased property and equipment meeting capital lease criteria are capitalized at the original cost of the equipment and are included within property plant and equipment on the Partnership s consolidated balance sheets.

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Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership s consolidated balance sheets (see Note 13). Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets. The Partnership did not enter into any capital lease arrangements during the year ended December 31, 2009, and had no capital lease obligations as of December 31, 2009.

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.

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 goodwill and other asset impairments on the Partnership s consolidated statements of operations. No impairment charges were recognized for the year ended December 31, 2010.

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 7.5%, 6.4% and 6.3% for the years ended December 31, 2010, 2009 and 2008, respectively. The amount of interest capitalized was $0.8 million, $2.6 million and $3.8 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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. Changes in a derivative instrument s fair value are recognized currently in the consolidated statements of operations. On July 1, 2008, the Partnership discontinued hedge accounting for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. Prior to discontinuance of hedge accounting, the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive loss within Equity on the Partnership s consolidated balance sheets and reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affect earnings.

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, 2010 and 2009 (in thousands):

	December 31, 2010	December 31, 2009(1)	Estimated Useful Lives In Years
Customer relationships:			
Gross carrying amount	$ 205,313	$ 205,313	7 10
Accumulated amortization	(78,934)	(55,832)	
Net carrying amount	$ 126,379	$ 149,481	

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

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. Amortization expense on intangible assets was $23.1 million for each of the years ended December 31, 2010, 2009 and 2008. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2011 to 2013 - $23.1 million; 2014 - $19.5 million; 2015 - $14.5 million.

Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2010, 2009 and 2008 were as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008(1)
Balance, beginning of year	$	$	$ 648,147
Post-closing purchase price adjustment with seller and purchase price allocation adjustment-Chaney Dell and Midkiff/Benedum acquisition			(2,217)
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/Benedum acquisition			(30,206)
Impairment loss			(615,724)
Balance, end of year	$	$	$

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

The Partnership tests its goodwill for impairment at each year end by comparing reporting unit estimated fair values to carrying values. As a result of its impairment evaluation at December 31, 2008, the Partnership recognized a $615.7 million non-cash impairment charge within its consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in the Partnership s estimated fair value of its reporting units in comparison to their carrying amounts at December 31, 2008. The Partnership s estimated fair value of its reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008.

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The Partnership had adjusted its preliminary purchase price allocation for the acquisition of its Chaney Dell and Midkiff/Benedum systems since its July 2007 acquisition date by adjusting the estimated amounts allocated to goodwill, intangible assets and property, plant and equipment. Also, in April 2008, the Partnership received a $30.2 million cash reimbursement for sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems in July 2007. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition.

Income Taxes

The Partnership is 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, 2010.

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 2007. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2010.

Stock-Based Compensation

All share-based payments to employees, including grants of employee stock options, are to be recognized in the financial statements based on their fair values. 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

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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 that the partnership agreement contractually limits cash distributions to available cash and, 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 after 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, 2010	2009[1]	2008[1]
Continuing operations:			
Net loss	$ (40,717)	$ (21,434)	$ (510,896)
(Income) loss attributable to non-controlling interest	(4,738)	(3,176)	22,781
Preferred unit dividends	(780)	(900)	(1,769)
Preferred unit imputed dividend cost			(505)
Net loss attributable to common limited partners and the General Partner	(46,235)	(25,510)	(490,389)
General Partner s actual cash incentive distributions declared			(23,472)
General Partner s actual ownership interest	888	513	10,328
Net (income) loss attributable to the general partner s ownership interests	888	513	(13,144)
Net loss attributable to common limited partners	(45,347)	(24,997)	(503,533)
Less: net loss attributable to participating securities phantom units[2]			2,109
Net loss utilized in the calculation of net loss from continuing operations attributable to common limited partners per unit	$ (45,347)	$ (24,997)	$ (501,424)
Discontinued operations:			
Net income (loss)	$ 321,155	$ 84,148	$ (93,802)
Net (income) loss attributable to the general partner s ownership interests	(6,134)	(1,691)	1,885
Net income (loss) utilized in the calculation of net income (loss) from discontinued operations attributable to common limited partners per unit	$ 315,021	$ 82,457	$ (91,917)

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

(2) 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 by the sum of the weighted average number of common limited partner units outstanding, including participating securities, plus the dilutive effect of 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,		
	2010	2009	2008
Weighted average number of common limited partner units - basic	53,166	48,299	42,513
Add: effect of participating securities-phantom units(1)			
Add: effect of dilutive option incentive awards(2)			
Add: effect of dilutive unit warrants(3)			
Add: effect of dilutive convertible preferred limited partner units(4)			
Weighted average common limited partner units - diluted	53,166	48,299	42,513

(1) For the years ended December 31, 2010, 2009 and 2008, approximately 300,000, 82,000 and 146,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

(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, 2008.

(3) For the year ended December 31, 2009, potential common limited partner units issuable upon exercise of the Partnership s warrants (see Note 5) were excluded from 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, 2010 and 2008.

(4) For the year ended December 31, 2008, potential common limited partner units issuable upon conversion of the Partnership s 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. There were no convertible preferred limited partner units outstanding for the years ended December 31, 2010 and 2009 (see Note 6 for additional information regarding the conversion features of the preferred limited partner units).

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 cap and trade programs or traditional permitting programs related to greenhouse gas emissions. The Partnership maintains insurance which may cover, in whole or in part, certain environmental expenditures. At December 31, 2010 and 2009, the Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments. The Mid-Continent segment consists of the Chaney Dell, Velma and Midkiff/Benedum operations, which are comprised of natural gas gathering and processing assets located in Oklahoma, Texas, and southern Kansas. The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in the Appalachian Basin area in northeastern United States. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas. Appalachia revenues are principally based on contractual arrangements with ATLS and its affiliates. These reportable segments reflect the way the Partnership manages its operations.

Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and liquids along with the fees earned from its gathering and processing 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 natural gas liquids (NGLs), if any, off of 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 is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing 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. Revenue is a function of the volume of natural gas that the Partnership gathers and processes and is not directly dependent on the value of the natural gas. The Partnership is also paid a separate compression fee on many of its 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.

Percentage of Proceeds (POP) Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural 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. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership s processing facility will be lower than the volume purchased at the wellhead primarily due to NGLs extracted when processed through a plant. The Partnership must make up or keep the producer whole for this loss in volume. 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 (i) the volume of residue gas available for redelivery to the producer may be less than received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that 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 Keep-Whole agreements is often 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 of margin risk.

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, 2010 and 2009 of $57.8 million and $61.2 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

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Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as other comprehensive income (loss) or OCI and for the Partnership only include changes in the fair value of unsettled derivative contracts which are accounted for as cash flow hedges (see Note 11).

Recently Adopted Accounting Standards

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2010-06, Fair Value Measurements and Disclosures - Improving Disclosures about Fair Value Measurements, which provides enhanced disclosure requirements for activity in Levels 1, 2 and 3 fair value measurements. The update requires significant transfers in and out of Levels 1 and 2 fair value measurements to be reported separately and the reasons for such transfers to be disclosed. The update also requires information regarding purchases, sales, issuances, and settlements to be disclosed separately on a gross basis in the reconciliation of fair value measurements using unobservable inputs for all activity in Level 3 fair value measurements. Additionally, the update clarifies that fair value measurement for each class of assets and liabilities must be disclosed as well as disclosures pertaining to the inputs and valuation techniques for both recurring and nonrecurring fair value measurements in Levels 2 and 3. These requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those requirements are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The Partnership adopted these requirements on January 1, 2010 and it did not have a material impact on its financial position, results of operations or related disclosures.

NOTE 3 INVESTMENT IN JOINT VENTURE

On May 31, 2009, the Partnership and subsidiaries of 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, excluding the Partnership s Tennessee operations. 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 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).

In connection with the formation of Laurel Mountain, Laurel Mountain entered into natural gas gathering agreements with Atlas Energy Resources which superseded the existing natural gas gathering agreements and omnibus agreement between the Partnership and Atlas Energy Resources. Under the new gas gathering agreement, Atlas Energy Resources is obligated to pay a gathering fee that is generally the same as the gathering fee required under the terminated agreements, the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). The Partnership has 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. During the years ended December 31, 2010 and 2009, the Partnership utilized $15.3 million and $1.7 million, respectively, of the $25.5 million note receivable to make capital contributions to Laurel Mountain and made additional capital contributions of $26.5 million in cash payments in the year ended December 31, 2010. As of December 31, 2010, the Partnership had $8.5 million of the $25.5 million note receivable remaining to fund capital contributions, which is included in investment in joint ventures on the consolidated balance sheets. Any amount that remains outstanding on this note after June 1, 2012 will be paid to the Partnership in cash.

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources for $413.5 million in cash, including certain closing adjustments (See Note 21). The Partnership retained its preferred distribution rights with respect to the remaining $8.5 million note receivable, due from Williams, related to formation of Laurel Mountain in 2009. During the year ended December 31, 2010, the Partnership incurred expenses related to the pending sale of Laurel Mountain, which are included in gain (loss) on sale of assets and other within the Partnership s consolidated statements of operations. The Partnership intends to utilize the proceeds from the sale to repay its indebtedness, to fund future capital expenditures, and for general corporate purposes.

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, 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 cash proceeds of $682.0 million, exclusive of working capital adjustments and transaction costs. The Partnership accounted for the earnings of Elk City as discontinued operations within its consolidated financial statements and recorded 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. Elk City was previously reported within the Partnership s Mid-Continent segment of operations.

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

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	2010	Years Ended December 31, 2009	2008
NOARK			
Total revenue and other income (loss), net	$	$ 21,274	$ 62,423
Total costs and expenses		(9,857)	(41,877)
Gain on asset sales and other		51,078	
Income from NOARK discontinued operations		62,495	20,546
Elk City			
Total revenue and other income (loss), net	129,908	167,543	180,366
Total costs and expenses	(120,855)	(148,383)	(294,714)
Gain on asset sales and other	312,102	2,493	
Income (loss) from Elk City discontinued operations	321,155	21,653	(114,348)
Total income (loss) from discontinued operations	$ 321,155	$ 84,148	$ (93,802)

During the year ended December 31, 2008, the Partnership recognized on its consolidated statements of operations, within income from discontinued operations, $61.1 million of goodwill impairment charges related to Elk City and impairment charges totaling $21.6 million in connection with a write-off of costs related to NOARK s pipeline expansion project. The costs incurred for the pipeline expansion consisted of preliminary construction and engineering costs incurred as well as a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

The following table summarizes the components included within total assets and liabilities of discontinued operations, all of which relate to Elk City, within the Partnership s consolidated balance sheets for the year ended December 31, 2009 (in thousands):

	December 31, 2009
Cash and cash equivalents	$
Accounts receivable	20,702
Prepaid expenses and other	2,044
Total current assets of discontinued operations	22,746
Property, plant and equipment, net	356,680
Intangible assets, net	18,610
Other assets, net	3,740
Total assets of discontinued operations	$ 401,776
Accounts payable	$ 3,372
Accrued liabilities	1,028
Accrued producer liabilities	8,781
Total current liabilities of discontinued operations	$ 13,181

NOTE 5 COMMON UNIT EQUITY OFFERINGS

In June 2008, the Partnership sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, the Partnership sold 1,112,000 common units to ATLS and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. The Partnership also received a capital contribution from the General Partner of $5.4 million for the General

Partner to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Note 11).

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 December 2008, the Partnership redeemed 10,000 of the then-outstanding 40,000 6.5% cumulative convertible preferred units (Class A Preferred Units), held by Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for $10.0 million in cash under the terms of the agreement. The redemption was classified as a reduction of Class A Preferred Equity within Equity on the Partnership s consolidated balance sheets.

In January 2009, the Partnership and Sunlight Capital amended certain terms of the Class A Preferred Units. 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. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense within the Partnership s

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consolidated statements of operations over the term of the notes based upon the effective interest rate method.

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.

The initial issuances of the 40,000 Class A Preferred Units were recorded on the consolidated balance sheets at the amount of net proceeds received less an imputed dividend cost. As a result of an amendment to the preferred units certificate of designation in March 2007, the Partnership, in lieu of dividend payments to Sunlight Capital, recognized an imputed dividend cost of $2.5 million that was amortized over a twelve-month period commencing March 2007 and was based upon the present value of the net proceeds received using the then 6.5% stated dividend yield. During the twelve months ended December 31, 2008, the Partnership amortized the remaining $0.5 million of this imputed dividend cost, which is presented as an additional adjustment of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on the Partnership s consolidated statements of operations for the year ended December 31, 2008.

Class B Preferred Units

In December 2008, the Partnership sold 10,000 Class B Preferred Units (the Class B Preferred Units) to AHD 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). On March 30, 2009, AHD purchased an additional 5,000 Class B Preferred Units at Face Value for net proceeds of $5.0 million. The Partnership used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units received distributions of 12.0% per annum. Additionally, on March 30, 2009, the Partnership and AHD 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 AHD was exempt from the registration requirements of the Securities Act of 1933.

On November 15, 2010, the Partnership redeemed the 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 ATLS for cash consideration of $1,000 per Class C Preferred Unit (the Class C Preferred Unit Face Value). The Partnership used the proceeds from the sale of the Class C Preferred Units for general partnership purposes. The Class C Preferred Units are 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 are not convertible into common units of the Partnership. The Partnership has the right at any time to redeem some or all of the outstanding Class C Preferred Units (but not less than 2,500 Class C Preferred Units) for cash at an amount equal to the Class C Preferred Face Value being redeemed plus accrued but unpaid dividends.

The sale of the Class C Preferred Units to ATLS was exempt from the registration requirements of the Securities Act of 1933. The Class C Preferred Units are reflected on the Partnership s consolidated balance sheets as Class C preferred limited partners interest within Equity.

The Partnership recognized $0.5 million of preferred dividend cost for the year ended December 31, 2010, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations.

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 AHD, Atlas Pipeline Holdings II, LLC (AHD Sub) for cash consideration of $1,000 per unit, for an aggregate investment of $15.0 million. AHD used the proceeds from its preferred unit offering to the Partnership to reduce indebtedness under its credit facility.

The preferred units were to receive cash distributions of 12.0% per annum, to be paid quarterly. The Partnership received distributions of $2.4 million on November 18, 2010, representing the accrued quarterly distributions. 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 AHD 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 were no preferred units outstanding at December 31, 2010.

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NOTE 8 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of 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. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2008 through December 31, 2010 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, 2007	February 14, 2008	$ 0.93	$ 36,051	$ 5,092
March 31, 2008	May 15, 2008	0.94	36,450	7,891
June 30, 2008	August 14, 2008	0.96	44,096	9,308
September 30, 2008	November 14, 2008	0.96	44,105	9,312
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

In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems, the General Partner, which holds all of 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 (the IDR Adjustment Agreement).

On January 25, 2011, the Partnership declared a cash distribution of $0.37 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2010. The $20.1 million distribution, including $0.4 million to the General Partner for its general partner interest, was paid on February 14, 2011 to unitholders of record at the close of business on February 7, 2011.

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NOTE 9 PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment (in thousands):

	December 31, 2010	December 31, 2009[1]	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,340,944	$ 1,281,366	2 40
Rights of way	156,713	152,908	20 40
Buildings	8,047	8,047	40
Furniture and equipment	8,981	8,848	3 7
Other	12,659	11,633	3 10
	1,527,344	1,462,802	
Less accumulated depreciation	(186,342)	(135,098)	
	$ 1,341,002	$ 1,327,704	

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

NOTE 10 OTHER ASSETS

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

	December 31, 2010	December 31, 2009[1]
Deferred finance costs, net of accumulated amortization of $24,436 and $25,314 at December 31, 2010 and 2009, respectively	$ 26,227	$ 27,331
Security deposits	2,841	2,922
	$ 29,068	$ 30,253

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

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, 2010, 2009 and 2008, the Partnership recorded $4.4 million, $2.5 million and $2.5 million, respectively, related to accelerated amortization of deferred financing costs associated with the retirement of its term loan. Total amortization expense of deferred finance costs was $10.5 million, $8.0 million and $5.9 million for the years ended December 31, 2010, 2009 and 2008, 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: 2011 to 2014 - $5.0 million; 2015 - $4.7 million.

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NOTE 11 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its 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. 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 or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period.

On July 1, 2008, the Partnership discontinued hedge accounting for certain existing qualified crude oil derivatives, utilized to hedge forecasted NGL production, due to significant ineffectiveness. The Partnership also discontinued hedge accounting for all of its other qualified commodity derivatives for consistency in reporting of all commodity-based derivatives. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008, which was 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 portion of any gain or loss in other comprehensive income related to originally forecasted transactions that are no longer expected to occur are removed from other comprehensive income and recognized within the statements of operations. In September 2010, the Partnership sold its Elk City assets (see Note 4), thus the Partnership 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 the Elk City operations are no longer expected to occur. The $10.6 million loss reclassed from other comprehensive income includes $1.4 million related to derivatives which were settled early and $9.2 million related to derivatives which will settle in future periods.

Derivatives are recorded on the Partnership s consolidated balance sheets as assets or liabilities at fair value. 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 other income (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premium costs are reclassified to realized gain (loss) within other income (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative liabilities on its consolidated balance sheets of $10.2 million and $43.3 million, at December 31, 2010 and 2009, respectively. The Partnership will reclassify $6.3 million of the $11.2 million net loss in accumulated other comprehensive loss within Equity on the Partnership s consolidated balance sheets at December 31, 2010, to natural gas and liquids revenue on the Partnership s consolidated statements of operations over the next twelve month period. Aggregate losses of $4.9 million will be reclassified to natural gas and liquids revenue on the Partnership s consolidated statements of operations in later periods. At December 31, 2010, no derivative instruments are designated as hedges for hedge accounting purposes.

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

	December 31, 2010	December 31, 2009
Current portion of derivative asset	$	$ 998
Long-term derivative asset		361
Current portion of derivative liability	(4,564)	(33,547)
Long-term derivative liability	(5,608)	(11,126)
	$ (10,172)	$ (43,314)

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

Contract Type	Balance Sheet Location	December 31, 2010	December 31, 2009
Asset Derivatives			
Commodity contracts	Current portion of derivative asset	$	$ 1,591
Commodity contracts	Long-term derivative asset		361
Commodity contracts	Current portion of derivative liability	2,624	6,562
Commodity contracts	Long-term derivative liability	1,052	3,435
		3,676	11,949
Liability Derivatives			
Interest rate contracts	Current portion of derivative liability		(2,247)
Interest rate contracts	Current portion of derivative asset		(593)
Commodity contracts	Current portion of derivative liability	(7,188)	(37,862)
Commodity contracts	Long-term derivative liability	(6,660)	(14,561)
		(13,848)	(55,263)
Total Derivatives		$ (10,172)	$ (43,314)

The following table summarizes the Partnership s commodity derivatives as of December 31, 2010, none of which are designated for hedge accounting (dollars and volumes in thousands):

Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes[2]	Average Fixed Price	Fair Value[1] Asset/ (Liability)
Natural Gas					
2011	Sold	Natural Gas Basis	1,920	(0.728)	$ (886)
2011	Purchased	Natural Gas Basis	1,920	(0.758)	944
2011	Sold	Natural Gas	2,100	4.481	(66)
Natural Gas Liquids					
2011	Sold	Ethane	10,458	0.496	(788)
2011	Sold	Propane	16,758	1.161	(1,022)
2011	Sold	Isobutane	1,008	1.618	124
2011	Sold	Normal Butane	2,772	1.580	(23)
2011	Sold	Natural Gasoline	1,764	1.990	(81)
Crude Oil					
2011	Sold	Crude Oil	138	91.92	(227)

Total Fixed Price Swaps	$	(2,025)

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Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[2]	Average Strike Price	Fair Value[1] Asset/ (Liability)
Crude Oil						
2011	Purchased	Put	Crude Oil	420	89.00	1,357
2011	Sold	Call	Crude Oil	678	94.68	(4,797)
2011	Purchased[3]	Call	Crude Oil	252	120.00	278
2012	Sold	Call	Crude Oil	498	95.83	(5,677)
2012	Purchased[3]	Call	Crude Oil	180	120.00	692
Total Options						$ (8,147)
Total Fair Value						$ (10,172)

(1) See Note 12 for discussion on fair value methodology.
(2) Volumes for natural gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.
(3) Calls purchased for 2011 and 2012 represent offsetting positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continue to rise.

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

		For the Years ended December 31, 2010	2009[1]	2008[1]
Gain (Loss) Recognized in Accumulated Other Comprehensive Income				
Contract Type				
Interest rate contracts[2]		$	$ (2,268)	$ (12,953)
Commodity contracts[2]				(112,824)
		$	$ (2,268)	$ (125,777)
Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Income				
Contract Type	**Location**			
Interest rate contracts[2]	Interest expense	$ (2,242)	$ (11,754)	$ (1,226)
Commodity contracts[2]	Natural gas and liquids revenue	(15,570)	(31,000)	(45,866)
Commodity contracts[2]	Discontinued operations	(20,154)	(15,268)	(35,791)
		$ (37,966)	$ (58,022)	$ (82,883)
Gain (Loss) Recognized in Income (Ineffective portion and derivatives not designated as hedges)				
Contract Type	**Location**			
Interest rate contracts[2]	Other income (loss), net	$ (6)	$ (1,041)	$
Commodity contracts[2]	Natural gas and liquids revenue		273	(23,359)
Commodity contracts[2]	Other income (loss), net			(270,999)
Commodity contracts[2]	Discontinued operations		(396)	7,022

Commodity contracts(3)	Other income (loss), net	(5,939)	(34,774)	300,740
Commodity contracts(3)	Discontinued operations	665	(1,190)	(100,243)
		$ (5,280)	$ (37,128)	$ (86,839)

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).
(2) Hedges previously designated as cash flow hedges.
(3) Dedesignated cash flow hedges and non-designated hedges.

During the years ended December 31, 2010, 2009 and 2008 the Partnership made net payments of $25.3 million, $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through 2012.

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NOTE 12   FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative 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 assumption 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 (see Note 11). At December 31, 2010, all of 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.

On June 30, 2009, the Partnership changed the basis for its valuation of crude oil options. Previously, the Partnership utilized forward price curves developed by its derivative counterparties. Effective June 30, 2009, the Partnership utilized crude oil option prices quoted from a public commodity exchange. With this change in valuation basis, the Partnership reclassified the inputs for the valuation of its crude oil options from a Level 3 input to a Level 2 input. The change in valuation basis did not materially impact the fair value of its derivative instruments on its consolidated statements of operations.

The following table represents the Partnership s derivative assets and liabilities recorded at fair value as of December 31, 2010 and 2009 (in thousands):

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	Level 1	Level 2	Level 3	Total
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)
December 31, 2009				
Assets				
Commodity swaps	$	$ 4,540	$	$ 4,540
Commodity options		6,141	1,268	7,409
Total assets		10,681	1,268	11,949
Liabilities				
Interest rate swaps		(2,840)		(2,840)
Commodity swaps		(16,355)		(16,355)
Commodity options		(36,068)		(36,068)
Total liabilities		(55,263)		(55,263)
Total derivatives	$	$ (44,582)	$ 1,268	$ (43,314)

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, 2010 and 2009 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Crude Oil Options		Total
	Volume[1]	Amount	Volume[1]	Amount	Volume[1]	Amount	Amount
Balance December 31, 2008	8,568	$ 1,509	28,904	$ 12,316	6,372	$ (23,436)	$ (9,611)
New contracts	6,804		93,870				
Cash settlements from unrealized gain (loss)[2][4]	(15,372)	(5,527)	(79,304)	(7,065)	1,434	(37,671)	(50,263)
Cash settlements from other comprehensive income[3]		7,153				11,618	18,771
Net change in unrealized loss[2]		(3,135)		(10,552)		14,886	1,199
Option premium recognition[4]				6,569		2,239	8,808
Transfer to Level 2					(7,806)	32,364	32,364
Balance December 31, 2009		$	43,470	$ 1,268		$	$ 1,268

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	NGL Fixed Price Swaps		NGL Put Options		Crude Oil Options		Total
	Volume(1)	Amount	Volume(1)	Amount	Volume(1)	Amount	Amount
Balance December 31, 2009		$	43,470	$ 1,268		$	$ 1,268
New contracts	57,246		8,820				
Cash settlements(2)(4)	(24,486)	1,634	(52,290)	7,246			8,880
Net change in unrealized loss(2)		(3,424)		(2,005)			(5,429)
Option premium recognition(4)				(6,509)			(6,509)
Balance December 31, 2010	32,760	$ (1,790)		$		$	$ (1,790)

(1) Volumes for NGLs are stated in gallons; volumes for crude oil are stated in barrels.
(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.
(3) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(4) 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 that 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, 2010 and 2009, which consists principally of borrowings under the credit facility, the term loan (repaid in September 2010), and the Senior Notes, was $532.3 million and $1,194.2 million, respectively, compared with the carrying amounts of $566.0 million and $1,254.2 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	December 31, 2010	December 31, 2009
Revolving credit facility	$ 70,000	$ 326,000
Term loan		433,505
8.125% Senior notes due 2015	272,181	271,628
8.75% Senior notes due 2018	223,050	223,050
Capital lease obligations	743	
Total debt	565,974	1,254,183
Less current maturities	(210)	
Total long-term debt	$ 565,764	$ 1,254,183

Term Loan and Revolving Credit Facility

At December 31, 2010, the Partnership had a senior secured credit facility with a syndicate of banks, which consisted of a $350.0 million revolving credit facility that matures in December 2015. A $425.8 million term loan, scheduled to mature in July 2014, was paid in full in September 2010 with proceeds received from the Elk City asset sale (see Note 4). Borrowings under the revolving credit facility bear interest, at the Partnership s option, at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2010 was 3.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $3.2 million was outstanding at December 31, 2010. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At December 31, 2010, the Partnership had $276.8 million of remaining committed capacity under its credit facility, subject to covenant limitations.

Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by Chaney Dell and Midkiff/Benedum joint ventures and Laurel Mountain; and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also unable to borrow under its 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 Partnership is in compliance with these covenants as of December 31, 2010.

The events which constitute an event of default for the 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.

On September 1, 2010, the Partnership entered into an amendment to its credit facility agreement, which, among other changes revised the definition of Consolidated EBITDA to provide for the add-back of charges relating to premiums associated with hedging agreements and to exclude the net gains or losses attributable to a disposition of assets other than in the ordinary course of business.

On December 22, 2010, the Partnership entered into an amended and restated credit facility agreement which, among other changes:

- set the maturity date of the revolving credit facility to December 22, 2015;
- reduced the revolving credit facility from $380.0 million to $350.0 million;
- eliminated the 2.0% per annum floor previously applied to adjusted LIBOR;
- revised the Applicable Margin used to determine interest rates;
- removed restrictions on making investments in the Laurel Mountain joint venture if specified financial thresholds are not met;

eliminated the requirements that the Partnership meet specified financial thresholds in order to be permitted to make distributions to its unitholders;

eliminated the limits on annual capital expenditures if specified financial thresholds are not met; and

adjusted the maximum Consolidated Funded Debt Ratio (leverage ratio) to 5.0 to 1.0; the maximum Consolidated Senior Secured Funded Debt Ratio (senior secured leverage ratio) to 3.0 to 1.0; and the minimum Interest Coverage Ratio to 2.5 to 1.0.

As of December 31, 2010, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At December 31, 2010, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $3.4 million of unamortized discount as of December 31, 2010. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its credit facility.

In January 2009, the Partnership issued Sunlight Capital $15.0 million of its 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 is presented as a reduction of long-term debt on its consolidated balance sheets. The discount recognized upon issuance of the Senior Notes will be 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.

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 allows 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 will be amortized over the remaining life of the 8.125% Senior Notes.

In connection with the issuance of the 8.75% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer

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registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If the Partnership did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that the Partnership had caused the exchange offer to be consummated. On November 21, 2008, the Partnership filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of December 31, 2010.

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

Years Ended December 31:	
2011	$ 210
2012	226
2013	243
2014	64
2015	345,479
Thereafter	223,050
Total principle maturities	569,272
Net unamortized discount	(3,298)
Total debt	$ 565,974

Cash payments for interest related to debt were $88.8 million, $90.7 million and $86.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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, 2010, 2009 and 2008 was $6.4 million, $6.8 million and $7.0 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2010 is as follows (in thousands):

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Years Ended December 31:	
2011	$ 4,737
2012	3,651
2013	1,644
2014	77
2015	47
Thereafter	
	$ 10,156

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.

On February 26, 2010, the Partnership received notice from Williams, its joint venture partner in Laurel Mountain, alleging that certain title defects exist with respect to the real property contributed by the Partnership to Laurel Mountain. Under the Formation and Exchange Agreement with Williams (Formation Agreement) : (i) Williams had nine months after closing (the Claim Date) to assert any alleged title defects, and (ii) the Partnership had 30 days following the Claim Date to contest the title defects asserted by Williams and 180 days following the Claim Date to cure those title defects. On March 26, 2010, the Partnership delivered notice, disputing Williams alleged title defects as well as the amounts claimed. By agreement dated December 22, 2010, Williams agreed to extend the cure period until March 31, 2011. ATLS has delivered a proposed assignment to Laurel Mountain that should resolve some of the alleged deficiencies. At the end of the cure period, with respect to any remaining title defects, the Partnership may elect, at its option, to pay Williams for the cost of such defects, up to a total of $3.5 million, or indemnify Williams with respect to such title defects. Williams also claims, in a letter dated August 26, 2010, that the alleged title defects violate the Partnership s representation with respect to sufficiency of the assets contributed to Laurel Mountain. If valid, this would make Williams title defect claims subject to a higher deductible (which is noted below). The Partnership believes its representations with respect to title are Williams sole and exclusive remedy with respect to title matters.

In August 2010, Williams asserted additional indemnity claims under the Formation Agreement totaling approximately $19.8 million. Williams claims are generally based on the Partnership s alleged failure to construct and maintain the assets contributed to Laurel Mountain in accordance with standard industry practice or applicable law. As a preliminary matter, the Partnership believes Williams has overstated its claim by forty-nine percent (49%), because, under the Formation Agreement, these claims are reduced on a pro-rata basis to equal Williams percentage ownership interest in Laurel Mountain. The Partnership has received some additional information from Williams and, based on the Partnership s analysis of that information, believes that an adverse outcome is probable with respect to some portion of Williams claims.

The Partnership has established an accrual with respect to the portion of Williams claims that it deems probable, which is less that 51% of the amounts asserted by Williams. Under the Formation Agreement, Williams indemnity claims are capped, in the aggregate, at $27.5 million. In addition, the Partnership is entitled to indemnification from ATLS with respect to some of Williams claims.

Following the November 9, 2010 announcement (the Announcement) that ATLS had entered into a definitive agreement to be acquired by Chevron Corporation (the Merger) and that AHD and the Partnership agreed to enter into separate transactions with ATLS relating to certain ATLS natural gas reserves and other assets and fee revenues, and the Partnership s interest in Laurel Mountain (the

Transactions), with each of the Transactions and the Merger to be cross-conditioned on the completion of the others, a purported class action was filed on November 15, 2010, in Delaware Chancery Court on behalf of a class of ATLS shareholders, Katsman v. ATLS, et al., C.A. No. 5990-VCL. The complaint named AHD and the Partnership and alleges that the ATLS directors violated their fiduciary duties in connection with the proposed Merger and that AHD, the Partnership, and Chevron aided and abetted the alleged breaches of fiduciary duty, and requested, among other relief, injunctive relief and damages. This lawsuit was consolidated in Delaware Chancery with other class actions that have been filed against ATLS and its directors, among others. On December 28, 2010, the plaintiffs filed an amended complaint in which all claims against the Partnership and APL were dropped.

Additionally, following the Announcement, a purported shareholder derivative case was filed on November 16, 2010, in the Western District of Pennsylvania federal court, Ussach v. ATLS, et al., C.A. No. 2:10-cv-1533. The complaint is asserted derivatively on behalf of the Partnership and names ATLS, the General Partner, and members of the Managing Board of the General Partner as defendants (Defendants) and alleges that Defendants have violated their fiduciary duties in connection with the proposed sale to ATLS of the Partnership s interest in Laurel Mountain and that ATLS has been unjustly enriched. In the complaint, among other relief, the plaintiff requests damages and equitable and injunctive relief, as well as restitution and disgorgement from the individual defendants. On February 22, 2011, the plaintiff voluntarily dismissed its complaint without prejudice. The Partnership has not received an indication whether the plaintiff intends to reassert its claim in another forum. In any event, the defendants believe the claims are without merit.

NOTE 15 CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas and NGLs under contract to various purchasers in the normal course of business. 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. For the year ended December 31, 2008, the Partnership had two customers that individually accounted for approximately 48% 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 55% and 17%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2010, and two customers that individually accounted for approximately 42% and 14%, respectively, of the Partnership s consolidated accounts receivable at December 31, 2009.

The Partnership has certain producers which supply a majority of the natural gas to its Mid-Continent 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, 2010, the Partnership and its subsidiaries had $2.4 million in deposits at banks, of which $1.4 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

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NOTE 16 BENEFIT PLANS

Generally, all share-based payments to employees, including grants of unit options and phantom units, which are not cash settled, are recognized in the financial statements based on their fair values on the date of the grant.

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, 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.

Partnership s 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. On June 15, 2010, the Partnership s unitholders approved the terms of the 2010 LTIP, which provides for the grant of options, phantom units, unit awards, unit appreciation rights and distribution equivalent rights (DERs). Under the 2010 LTIP, the LTIP Committee may make awards of either phantom units or unit options for an aggregate of 3,000,000 common units, in addition to the 435,000 common units authorized in the 2004 LTIP. At December 31, 2010, the Partnership had 565,886 phantom units and unit options outstanding under the Partnership s LTIPs, with 2,501,347 phantom units and unit options available for grant.

Partnership Phantom Units. Through December 31, 2010, 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 of the 375,000 equity indexed bonus units (Bonus Units), under the Partnership s subsidiary s plan discussed below, agreed to exchange their Bonus Units for an equivalent number of phantom units, effective as of June 1, 2010. These phantom units will vest over a two year period, including the first tranche, which vested on June 1, 2010. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIPs. At December 31, 2010, there were 174,687 units outstanding under the LTIPs that will vest within the following twelve months. All phantom units outstanding under the LTIPs at December 31, 2010 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $0.2 million, $0.1 million and $0.5 million for the years ended December 31, 2010, 2009 and 2008, respectively. These amounts were recorded as reductions of Equity on the Partnership s consolidated balance sheets.

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

	Years Ended December 31,					
	2010		2009		2008	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	52,233	$ 39.72	126,565	$ 44.22	129,746	$ 45.75
Granted	575,112	10.49	2,000	4.75	54,796	44.28
Matured(2)	(126,584)	17.11	(58,257)	45.68	(56,227)	44.65
Forfeited	(9,875)	17.39	(18,075)	48.17	(1,750)	43.88
Outstanding, end of period(3)	490,886	$ 11.75	52,233	$ 39.72	126,565	$ 44.22
Non-cash compensation expense recognized						
(in thousands)(4)		$ 3,480		$ 694		$ 2,313

(1) Fair value based upon weighted average grant date price, which is utilized in the calculation of compensation expense.
(2) The intrinsic values for phantom unit awards exercised during the years ended December 31, 2010, 2009 and 2008 were $1.5 million, $0.3 million and $2.0 million, respectively.
(3) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2010 and 2009 was $12.1 million and $0.5 million, respectively.
(4) 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, 2010, the Partnership had approximately $2.3 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Partnership Unit Options. Through December 31, 2010, unit options granted under the Partnership s LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. Awards will automatically vest upon a change of control of the Partnership, as defined in the Partnership s LTIPs. There are 25,000 unit options outstanding under the Partnership s LTIPs at December 31, 2010 that will vest within the following twelve months.

The following table sets forth the LTIP unit option activity for the periods indicated (There were no outstanding unit options for the year ended December 31, 2008):

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	Years Ended December 31,			
	2010		2009	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	100,000	$ 6.24		$
Granted			100,000	6.24
Exercised[(1)]	(25,000)	6.24		
Outstanding, end of period[(2)(3)]	75,000	$ 6.24	100,000	$ 6.24
Options exercisable, end of period				
Weighted average fair value of unit options per unit granted during the period		$	100,000	$ 0.14
Non-cash compensation expense recognized (in thousands)		$ 4		$ 7

(1) The intrinsic values for option unit awards exercised during the year ended December 31, 2010 were $0.5 million. Approximately $0.2 million was received from exercise of option unit awards during the year ended December 31, 2010.

(2) The weighted average remaining contractual life for outstanding and exercisable options at December 31, 2010 and 2009 was 8.0 years and 9.0 years, respectively.

(3) The aggregate intrinsic value of options outstanding at December 31, 2010 and 2009 was $1.4 million and $0.4 million, respectively.

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

Incentive Compensation Agreements

The Partnership had incentive compensation agreements which granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive common units of the Partnership upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested.

Compensation expense is recognized on a straight-line basis over the vesting period. As of December 31, 2008, the Partnership recognized in full within its consolidated statements of operations the compensation expense associated with the vesting of awards issued under these incentive compensation agreements, therefore no compensation expense was recognized during the years ended December 31, 2010 and 2009. The Partnership recognized a reduction of compensation expense of $36.3 million for the year ended December 31, 2008 related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the year ended December 31, 2008 were principally attributable to changes in the Partnership s common unit market price, which was utilized in the calculation of the non-cash compensation expense for these awards, at December 31, 2008 when compared with the common unit market price at earlier periods and adjustments based upon the

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achievement of actual financial performance targets through December 31, 2008. The Partnership recognized compensation expense related to these awards based upon the fair value method. During the year ended December 31, 2009, the Partnership issued 348,620 common units to the certain key employees covered under the incentive compensation agreements. No additional common units will be issued with regard to these agreements.

Employee Incentive Compensation Plan and Agreement

In June 2009, a wholly-owned subsidiary of the Partnership adopted an incentive plan (the Cash Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants), but expressly excludes as an eligible Participant any person that, at the time of the grant, is a Named Executive Officer of the Partnership (as such term is defined under the rules of the Securities and Exchange Commission). The Cash Plan is administered by a committee appointed by the president and chief executive officer of the General Partner. Under the Cash Plan, cash bonus units may be awarded to Participants at the discretion of the committee, which granted 325,000 bonus units during 2009. In addition, the subsidiary granted an award of 50,000 bonus units to an executive officer on substantially the same terms as the bonus units available under the Cash Plan (the bonus units issued under the Cash Plan and under the separate agreement are, for purposes hereof, referred to as 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 of the 375,000 Bonus Units outstanding at June 16, 2010 agreed to exchange their Bonus Units for phantom units, effective as of June 1, 2010.

A total of 24,750 of the remaining 75,000 Bonus Units vested on June 1, 2010. Of the Bonus Units outstanding at December 31, 2010, 24,750 Bonus Units will 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 a credit of $0.2 million during the year ended December 31, 2010 and expense of $1.2 million during the year ended December 31, 2009, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had $0.8 million and $1.2 million, at December 31, 2010 and 2009, respectively, 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.

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The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $1.5 million, $2.7 million and $1.5 million for the years ended December 31, 2010, 2009 and 2008, 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, 2010, 2009 and 2008. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

On February 17, 2011, APL completed the sale of its 49% interest in Laurel Mountain Midstream, LLC, a Delaware limited liability company to Atlas Energy Resources for $413.5 million, which included certain adjustments (See Note 21).

NOTE 18 SEGMENT INFORMATION

The Partnership has two reportable segments. These reportable segments reflect the way the Partnership manages its operations.

The Mid-Continent segment consists of the Chaney Dell, Velma and Midkiff/Benedum operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in the Appalachian Basin and services drilling activity in the Marcellus Shale. Appalachia revenues are principally based on contractual arrangements with ATLS and its affiliates.

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

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Year Ended December 31, 2010:				
Revenue:				
Revenues third party[2]	$ 544	$ 955,939	$ (21,514)	$ 934,969
Revenues affiliates	619			619
Total revenue and other income (loss), net	1,163	955,939	(21,514)	935,588
Costs and Expenses:				
Operating costs and expenses	1,061	768,885		769,946
General and administrative[2] `			34,021	34,021
Depreciation and amortization	609	74,288		74,897
Interest expense[2]			91,632	91,632
Total costs and expenses	1,670	843,173	125,653	970,496
Equity income	4,920			4,920
Loss on asset sales and other	(10,729)			(10,729)
Net income (loss) from continuing operations	(6,316)	112,766	(147,167)	(40,717)
Income from discontinued operations			321,155	321,155
Net income (loss)	$ (6,316)	$ 112,766	$ 173,988	$ 280,438

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	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Year Ended December 31, 2009[1]:				
Revenue:				
Revenues third party[2]	$ 1,779	$ 719,832	$ (66,542)	$ 655,069
Revenues affiliates	17,536			17,536
Total revenue and other income (loss), net	19,315	719,832	(66,542)	672,605
Costs and expenses:				
Operating costs and expenses	6,917	573,036		579,953
General and administrative[2]			37,280	37,280
Depreciation and amortization	3,591	72,093		75,684
Goodwill and other asset impairment loss		10,325		10,325
Interest expense[2]			103,787	103,787
Total costs and expenses	10,508	655,454	141,067	807,029
Equity income	4,043			4,043
Gain on asset sales and other	108,947			108,947
Net income (loss) from continuing operation	121,797	64,378	(207,609)	(21,434)
Income from discontinued operations			84,148	84,148
Net income (loss)	$ 121,797	$ 64,378	$ (123,461)	$ 62,714
Year Ended December 31, 2008[1]:				
Revenue:				
Revenues third party[2]	$ 5,456	$ 1,193,478	$ (39,486)	$ 1,159,448
Revenues affiliates	43,293			43,293
Total revenue and other income (loss), net	48,749	1,193,478	(39,486)	1,202,741
Costs and expenses:				
Operating costs and expenses	13,073	946,007		959,080
General and administrative[2]			(2,933)	(2,933)
Depreciation and amortization	6,430	65,334		71,764
Goodwill and other asset impairment loss	2,304	613,420		615,724
Interest expense[2]			89,869	89,869
Gain on extinguishment of debt			(19,867)	(19,867)
Total costs and expenses	21,807	1,624,761	67,069	1,713,637
Net income (loss) from continuing operation	26,942	(431,283)	(106,555)	(510,896)
Loss from discontinued operations			(93,802)	(93,802)
Net income (loss)	$ 26,942	$ (431,283)	$ (200,357)	$ (604,698)

	Years Ended December 31,		
	2010	2009[1]	2008[1]
Capital Expenditures:			
Mid-Continent	$ 46,636	$ 100,712	$ 140,154
Appalachia		9,562	41,502

	$ 46,636	$ 110,274	$ 181,656

	December 31,	
	2010	**2009(1)**
Balance Sheets		
Total assets:		
Mid-Continent	$ 1,574,635	$ 1,563,443
Appalachia	163,858	170,905
Discontinued operations		401,776
Corporate and other	26,355	1,839
	$ 1,764,848	$ 2,137,963

The following tables summarize the Partnership s total natural gas and liquids revenues by

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product or service for the periods indicated (in thousands):

	Years Ended December 31,		
	2010	2009(1)(3)	2008(1)(3)
Natural gas and liquids:			
Natural gas	$ 299,461	$ 257,297	$ 504,768
NGLs	548,308	351,410	528,048
Condensate	41,933	23,626	48,694
Other(2)	346	3,898	(2,796)
Total.	$ 890,048	$ 636,231	$ 1,078,714

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

(2) The Partnership notes that derivative contracts, 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.

(3) Restated to reflect amount reclassified from natural gas and liquids revenue to transportation, processing and other fees (see Note 1).

NOTE 19 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s revolving credit facility is guaranteed by its wholly-owned subsidiaries (as was its term loan prior to it being repaid). The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of and for the years ended December 31, 2010, 2009 and 2008 include the financial statements of Chaney Dell LLC and Midkiff/Benedum, entities in which the Partnership has controlling interests (see Note 2). Under the terms of the term loan and revolving credit facility, Chaney Dell LLC and Midkiff/Benedum 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 and for the years ended December 31, 2010, 2009 and 2008. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in its subsidiaries are presented in accordance with the equity method of accounting (in thousands):

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Balance Sheets

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
December 31, 2010					
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
Notes receivable			1,852,928	(1,852,928)	
Equity investments	252,725	(633,455)		380,730	
Investment in joint venture		153,358			153,358
Intangible assets, net			126,379		126,379
Other assets, net	26,605	1,775	688		29,068
	$ 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
	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848
December 31, 2009[(1)]					
Assets					
Cash and cash equivalents	$	$ 1,021	$	$	$ 1,021
Accounts receivable affiliates	1,383,871			(1,383,871)	
Current portion of derivative asset		998			998
Other current asset		19,711	73,668		93,379
Current assets of discontinued operations		22,746			22,746
Total current assets	1,383,871	44,476	73,668	(1,383,871)	118,144
Property, plant and equipment, net		231,968	1,095,736		1,327,704
Notes receivable			1,852,928	(1,852,928)	
Equity investments	568,320	237,991		(806,311)	
Investment in joint venture		132,990			132,990
Intangible assets, net			149,481		149,481
Long-term derivative asset		361			361
Other assets, net	27,332	1,785	1,136		30,253
Long-term assets discontinued operations		379,030			379,030
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963

Liabilities and Equity					
Accounts payable affiliates	$	$ 1,251,468	$ 134,446	$ (1,383,871)	$ 2,043
Current portion of derivative liability		33,547			33,547
Other current liabilities	1,813	33,069	65,076		99,958
Current liabilities discontinued operations		13,181			13,181
Total current liabilities	1,813	1,331,265	199,522	(1,383,871)	148,729
Long-term derivative liability		11,126			11,126
Long-term debt, less current portion	1,254,183				1,254,183
Other long-term liability		398			398
Equity	723,527	(314,188)	2,973,427	(2,659,239)	723,527
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963

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Statements of Operations

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2010					
Total revenue and other income (loss), net	$	$ 168,057	$ 767,531	$	$ 935,588
Total costs and expenses	(43,947)	(271,876)	(654,673)		(970,496)
Equity income	328,799	116,812		(440,691)	4,920
Loss on asset sales and other		(10,729)			(10,729)
Income (loss) from continuing operations	284,852	2,264	112,858	(440,691)	(40,717)
Income from discontinued operations		321,155			321,155
Net income (loss)	$ 284,852	$ 323,419	$ 112,858	$ (440,691)	$ 280,438
Year Ended December 31, 2009[1]					
Total revenue and other income (loss), net	$	$ 71,639	$ 600,966	$	$ 672,605
Total costs and expenses	(103,629)	(194,995)	(508,405)		(807,029)
Equity income in subsidiaries	164,801	98,236		(258,994)	4,043
Gain on asset sales and other		108,947			108,947
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 (loss)	$ 61,172	$ 167,975	$ 92,561	$ (258,994)	$ 62,714
Year Ended December 31, 2008[1]					
Total revenue and other income (loss), net	$	$ 176,945	$ 1,025,796	$	$ 1,202,741
Total costs and expenses	(64,976)	(239,535)	(1,409,126)		(1,713,637)
Equity income in subsidiaries	(538,183)	(381,791)		919,974	
Income (loss) from continuing operations	(603,159)	(444,381)	(383,330)	919,974	(510,896)
Income from discontinued operations		(93,802)			(93,802)
Net income (loss)	$ (603,159)	$ (538,183)	$ (383,330)	$ 919,974	$ (604,698)

Statements of Cash Flows

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2010					
Net cash provided by (used in):					
Continuing operations	$ 386,703	$ 36,633	$ 178,148	$ (518,431)	$ 83,053
Discontinued operations		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 year	$		$	164	$		$		$	164

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	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2009(1)					
Net cash provided by (used in):					
Continuing operations	$ 153,969	$ (85,466)	$ 205,745	$ (260,537)	$ 13,711
Discontinued operations		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 year	7	1,438			1,445
Cash and cash equivalents, end of year	$	$ 1,021	$	$	$ 1,021
Year Ended December 31, 2008(1)					
Net cash provided by (used in):					
Continuing operations	$ 8,860	$ (776,634)	$ 363,886	$ 174,897	$ (228,991)
Discontinued operations		169,797			169,797
Total operating activities	8,860	(606,837)	363,886	174,897	(59,194)
Continuing investing activities	(350,102)	693,861	(53,030)	(439,831)	(149,102)
Discontinued investing activities		(143,842)			(143,842)
Total investing activities	(350,102)	550,019	(53,030)	(439,831)	(292,944)
Total financing activities	341,242	63,971	(328,905)	264,934	341,242
Net change in cash and cash equivalents		7,153	(18,049)		(10,896)
Cash and cash equivalents, beginning of year	7	(5,715)	18,049		12,341
Cash and cash equivalents, end of year	$ 7	$ 1,438	$	$	$ 1,445

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

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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, 2010:				
Revenue and other income (loss), net	$ 253,090	$ 226,118	$ 216,227	$ 240,153
Costs and expenses	(254,176)	(245,362)	(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 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 interest	(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:[5][6]				
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 21).

(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) 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.

(6) 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.

	Fourth Quarter[2]	Third Quarter[3]	Second Quarter[4]	First Quarter[5]
	(in thousands, except per unit data)			
Year ended December 31, 2009[1]:				
Revenue and other income (loss), net	$ 202,036	$ 176,281	$ 146,177	$ 148,111
Costs and expenses	(241,971)	(198,255)	(183,992)	(182,811)
Equity income in joint venture	1,903	1,430	710	
Gain (loss) on sale of asset		(994)	109,941	
Income (loss) from continuing operations	(38,032)	(21,538)	72,836	(34,700)
Income from discontinued operations	2,907	9,215	60,562	11,464
Net income (loss)	(35,125)	(12,323)	133,398	(23,236)
Income attributable to non-controlling interest	(1,101)	(954)	(652)	(469)
Preferred unit dividends				(900)
Net loss attributable to common limited partners and the General Partner	$ (36,226)	$ (13,277)	$ 132,746	$ (24,605)
Net income (loss) attributable to common limited partners per unit basic:				
Income (loss) from continuing operations attributable to common limited partners	$ (0.76)	$ (0.44)	$ 1.48	$ (0.76)
Income from discontinued operations attributable to common limited partners	0.06	0.18	1.25	0.24
Net income (loss) attributable to common limited partners	$ (0.70)	$ (0.26)	$ 2.73	$ (0.52)
Net income (loss) attributable to common limited partners per unit diluted:[6]				
Income (loss) from continuing operations attributable to common limited partners	$ (0.76)	$ (0.44)	$ 1.48	$ (0.76)
Income from discontinued operations attributable to common limited partners	0.06	0.18	1.25	0.24
Net income (loss) attributable to common limited partners	$ (0.70)	$ (0.26)	$ 2.73	$ (0.52)

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).
(2) Net loss includes an $11.7 million non-cash derivative loss and a $10.3 million non-cash impairment charge for goodwill and other assets.
(3) Net loss includes a $7.5 million non-cash derivative gain.
(4) Net income includes a $2.5 million non-cash derivative loss and a $79.8 million non-cash gain of the total $111.4 million gain on the sale of assets.
(5) Net loss includes a $44.0 million non-cash derivative loss and a $5.0 million cash derivative expense from the early termination of certain derivative instruments.
(6) For the first quarter of the year ended December 31, 2009, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units 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.

NOTE 21 SUBSEQUENT EVENTS

On February 17, 2011, the Partnership completed its sale to Atlas Energy Resources of its 49% non-controlling interest in Laurel Mountain (the Laurel Mountain Sale) for $413.5 million in cash, including adjustments based on certain capital contributions the Partnership made to and distributions it received from Laurel Mountain after January 1, 2011. The Partnership retained the preferred distribution rights under the limited liability company agreement of Laurel Mountain entitling APL Laurel Mountain 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.

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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, 2010, 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 Rules 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, 2010. Grant Thornton LLP, an independent registered public accounting firm and auditors of our consolidated

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financial statements, has issued its report on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2010, which is included herein.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2010 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, 2010, 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, 2010, 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, 2010 and 2009 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, 2010, and our report dated February 25, 2011 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 25, 2011

ITEM 9B. OTHER INFORMATION

None.

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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 of 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 board of directors 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 of the members of the managing board s committees: the conflicts committee and the 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, prior to the merger with Chevron Corporation, a Delaware corporation (Chevron), in which ATLS became a wholly-owned subsidiary of Chevron (the Chevron Merger), ATLS personnel managed and operated our business. Subsequent to the Chevron Merger, AHD 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 AHD (or ATLS prior to the Chevron Merger) 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:

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Name	Age	Position with the General Partner	Year in which service began
Edward E. Cohen	72	Chairman of the Managing Board	1999
Jonathan Z. Cohen	40	Vice Chairman of the Managing Board	1999
Eugene N. Dubay	62	Chief Executive Officer, President and Managing Board Member	2008
Eric T. Kalamaras	37	Chief Financial Officer	2009
Robert W. Karlovich, III	33	Chief Accounting Officer	2009
Gerald R. Shrader	51	Chief Legal Officer and Secretary	2009
Tony C. Banks	56	Managing Board Member	1999
Curtis D. Clifford	68	Managing Board Member	2004
Gayle P. W. Jackson	64	Managing Board Member	2011
Martin Rudolph	64	Managing Board Member	2005
Michael L. Staines	61	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 Holdings GP, the General Partner of Atlas Energy, L.P. (formerly known as Atlas Pipeline Holdings, L.P.), 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 Atlas Energy, L.P. from its formation until February 2009. Mr. Cohen also has been the Chairman of the Board and Chief Executive Officer of Atlas Energy, Inc. 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 became its wholly-owned subsidiary following its merger transaction. Mr. Cohen has been 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 Holdings GP 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 Atlas Energy, Inc. 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 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,

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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 Atlas Energy, L.P. 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 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.

Eric T. Kalamaras has nearly 15 years of financial management experience within the energy industry and has been the Chief Financial Officer of our General Partner since 2009. Mr. Kalamaras was the Chief Financial Officer of Atlas Energy, L.P. from 2009 until February 2011. From 2004 to 2009, Mr. Kalamaras was Director of Energy Leveraged Finance & High Yield for Wells Fargo Corporation (formerly Wachovia), where he led a team dedicated to providing financing solutions for a number of public and private leveraged companies within energy and natural resource industries. From 1999 to 2004, Mr. Kalamaras served as Vice President at Banc of America Merrill Lynch (formerly Bank of America) where he played lead roles in evaluating, and executing debt and equity financings, including follow-on and initial public offerings, as well as due diligence for M&A financing through the hydrocarbon value chain for companies in the exploration & production, energy services, midstream, and mining spaces. Mr. Kalamaras began his career as an analyst within Ford Motor Company s corporate finance department dedicated to analyzing and evaluating capital investments. Mr. Kalamaras holds a Masters in Business Administration degree from Wake Forest University, and a Bachelors in Business Administration degree from Central Michigan University. Mr. Kalamaras has completed significant continuing education studies in the fields of Petroleum Engineering and Geology.

Robert W. Karlovich, III has been the Chief Accounting Officer of our General Partner since November 2009. Mr. Karlovich has been the Chief Accounting Officer of Atlas Pipeline Holdings GP since November 2009. Before that, he was the Controller of Atlas Pipeline Mid-Continent, LLC, our wholly-owned subsidiary, 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 been the Chief Legal Officer and Secretary of Atlas Holdings GP since October 2009 and has also been the General Counsel and a Senior Vice President of Atlas Pipeline Mid-Continent, LLC since August 2007. From January 2006 through July 2007, Mr. Shrader was the

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Assistant General Counsel of CMS Enterprises Company, a subsidiary of CMS Energy Corporation, a publicly-traded energy company. From November 2005 through January 2006, he was the General Counsel of Atlas Pipeline Mid-Continent, LLC.

Tony C. Banks has been Vice President of Product and Market Development for FirstEnergy Solutions Corp., a subsidiary of FirstEnergy Corporation, a public utility, since October 2009. 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 Atlas Energy, Inc. In addition, Mr. Banks served as President of our General Partner during 2000. He was Chief Executive Officer and President of Atlas Energy, Inc. 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 Atlas Energy, Inc., 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 markets for natural gas.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Since January 2001, he has worked for UtiliTech, Inc., utility and telecommunications specialists in West Lawn, PA, where he advises and assists commercial and industrial gas consumers nationwide with procurement activities and utility rate options. As a prelude to retirement from UtiliTech, he reduced his workload there in July 2010 by transitioning to a consultant role with a reduced number of 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 44 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 Atlas Energy, Inc. 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 Atlas Energy, Inc. 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 35 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 Atlas Energy, Inc. from its formation in 2000 until July 2009. Mr. Staines was Senior Vice President of Resource America 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 complements 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.

We administer our risk oversight function through our Risk Oversight Committee which was appointed by our Managing Board to assist with its oversight duties for the risk management of the Partnership. 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

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Committee and to the Managing Board periodically on its activities and is generally responsible for overseeing the guidelines and policies that govern the Partnership s 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 the Partnership s framework for management of risks and reporting any significant changes or updates to the key risks of the Partnership to the Risk Oversight Committee. The management-level risk management committee reports to the CEO and the Risk Oversight Committee. Additionally, individuals at the Partnership 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 2010.

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. We reimbursed our General Partner and its affiliates $1.5 million for compensation and benefits during 2010.

Information Concerning the Audit Committee

Our managing board has a standing audit committee. All of 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, and Mr. Banks, with Mr. Rudolph acting as the chairman. Our managing board has determined that Mr. Rudolph is an audit committee financial expert, as defined by SEC rules. The audit committee reviews the scope and effectiveness of audits by the independent accountants, is responsible for the engagement of independent accountants and reviews the adequacy of our internal 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, 2010. Compensation of the personnel of ATLS and its affiliates who provided us with services was 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 Atlas Energy, Inc. until 2002. 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., Westpointe Corporate Center, 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108, 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.

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ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We are required to provide information regarding the compensation program in place as of December 31, 2010, for our General Partner s CEO, 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 named executive officers. For fiscal year 2010, ATLS allocated the compensation of our executive officers between activities on behalf of us and activities on behalf of itself and its other affiliates based upon an estimate of the time spent by such persons on activities for us and for ATLS and its affiliates. Because Messrs. Dubay, Kalamaras, and Shrader devoted all of their time to us and AHD, all of their compensation costs were allocated to us. We reimbursed ATLS for the compensation allocated to us. Because ATLS employed our NEOs, 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.

As a result of recent transactions, AHD s general partner now employs our NEOs and AHD s compensation committee will be responsible for formulating and presenting recommendations to its Board of Directors with respect to the compensation of our NEOs effective February 2011. See Item 1: Business Recent Developments for further discussion. While the discussion that follows regarding our compensation program reflects the compensation program in place by the ATLS compensation committee, we anticipate that our compensation program going forward will be substantially the same, except that our NEOs will not receive stock-based awards from ATLS.

Compensation Objectives

We believe that our compensation program must support our business strategy, be competitive, and provide both significant rewards for outstanding performance and clear financial consequences for underperformance. We also believe that 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 made 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 recommended the amounts to be paid for the new fiscal year. In the case of annual bonus and long-term incentive compensation, the committee recommended the amount of awards based on the then concluded fiscal year. ATLS and we typically paid cash awards in February, although the ATLS compensation committee had 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 who also performed services for ATLS and its other subsidiaries received stock-based awards from ATLS and these subsidiaries, each of which had delegated compensation decisions to the ATLS compensation committee because they, like us, did not

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have their own employees. AHD s compensation committee was formed in February 2011 and, at its initial meeting, it recommended base salaries to be paid to some of our executive officers for our 2011 fiscal year and annual bonuses based on our 2010 fiscal year.

Prior to February 2011, each year, the Chairman of our general partner, who also served as ATLS s Chief Executive Officer and Chairman, provided the ATLS compensation committee with key elements of ATLS s, our and our NEOs performance during the year. The Chairman made recommendations to the compensation committee regarding the salary, bonus, and incentive compensation components of each NEO s total compensation. The Chairman, at the compensation committee s request, may have attended compensation committee meetings; however, his role during the meetings was to provide insight into ATLS s and our company s performance, as well as the performance of other comparable companies in the same industry.

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 s annual performance and /or that of one of ATLS s 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 would recommend awards of performance-based bonuses and discretionary bonuses.

Performance-Based Bonuses The ATLS Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, provides awards for the achievement of predetermined, objective performance measures over a specified 12-month performance period, generally ATLS s fiscal year. Awards under the Senior Executive Plan may be paid in cash or in shares of ATLS s common stock under its stock incentive plan. The Senior Executive Plan is designed to permit ATLS to qualify for an exemption from the $1,000,000 deduction limit under Section 162(m) of the Internal Revenue Code for compensation paid to the NEOs. Notwithstanding the existence of the Senior Executive Plan, the ATLS compensation committee believed that the interests of ATLS s stockholders and our unitholders were best served by not restricting its discretion and flexibility in crafting compensation, even if the compensation amounts result in non-deductible compensation expense. Therefore, the committee reserved the right to approve compensation that is not fully deductible.

In February 2010, the compensation committee approved 2010 target bonus awards to be paid from a bonus pool. The bonus pool was equal to 18.3% of ATLS s adjusted distributable cash flow unless the adjusted 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 adjusted distributable cash flow did not equal at least 75% of the average adjusted distributable cash flow for the previous

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3 years, no bonuses would be paid. Adjusted distributable cash flow means the sum of (i) cash available for distribution to ATLS by any of its subsidiaries (regardless of whether such cash is actually distributed), plus (ii) interest income during the year, plus (iii) to the extent not otherwise included in adjusted distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iv) ATLS s stand-alone general and administrative expenses for the year excluding any bonus expense (other than non-cash bonus compensation included in general and administrative expenses), and less (v) to the extent not otherwise included in adjusted distributable cash flow, any loss on the sale of securities, including securities of a subsidiary. A return of ATLS s capital investment in a subsidiary was not intended to be included and, accordingly, if adjusted 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 adjusted distributable cash flow would be reduced by its basis in the subsidiary. The maximum award payable, expressed as a percentage of ATLS s estimated 2010 adjusted distributable cash flow, for our NEO participants was as follows: Edward E. Cohen, 6.14% and Jonathan Z. Cohen, 4.37%. 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 plan.

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

Long-Term Incentives

We believe that 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 were also eligible to receive awards under the ATLS Stock Incentive Plans, which we refer to as the ATLS Plans, and the AHD Long-Term Incentive Plans, which we refer to as the AHD Plans, as appropriate.

Grants under our Plans: The ATLS compensation committee could recommend 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 employment agreement, only phantom units have been granted under our plans through December 31, 2010. The unit options and phantom units vest over four years.

Grants under Other Plans: As described above, our NEOs who perform services for us and one or more of ATLS s subsidiaries were eligible to receive stock-based awards under the ATLS Plans or the AHD Plans.

Supplemental Benefits, Deferred Compensation and Perquisites

We do not provide supplemental benefits for executives and perquisites are discouraged. ATLS did provide a Supplemental Executive Retirement Plan for Messrs. E. Cohen and J. Cohen pursuant to their employment agreements, but none of those benefits or related costs are allocated to us. None of our NEOs have deferred any portion of their compensation.

Employment Agreements

ATLS entered into employment agreements with Messrs. E. Cohen, J. Cohen, E. Dubay and E. Kalamaras. These employment agreements terminated upon closing of the Chevron Merger.

Determination of 2010 Compensation Amounts

At the end of ATLS s 2010 fiscal year, the ATLS compensation committee recommended incentive awards based on the prior year s performance for Messrs. E. and J. Cohen. The ATLS compensation committee had already approved our 2010 NEO s base salaries in February 2010. In February 2011, the newly formed AHD compensation committee approved the base salaries and bonuses for our NEOs.

In determining the actual amounts to be paid to the NEOs, the ATLS compensation committee and the AHD compensation committee considered both individual and company performance. Our CEO made recommendations of award amounts based upon the NEOs individual performances as well as the performance of ATLS s subsidiaries for which each NEO provided service; however, the ATLS compensation committee had, and AHD s compensation committee has, the discretion to approve, reject, or modify the recommendations.

Base Salary.

The AHD compensation committee set 2011 salaries for our NEOs as follows: Mr. Dubay $500,000, Mr. Kalamaras $295,000 and Mr. Shrader-$290,000. These amounts represent a 0%, 7% and 5% increase from the 2010 base salaries for each of Messrs. Dubay, Kalamaras and Shrader, respectively.

Annual Incentives.

Performance-Based Bonuses. The ATLS compensation committee noted, among other accomplishments, Atlas Energy Resource, LLC s joint venture with Reliance Industries Limited and the Chevron merger. ATLS substantially outperformed the incentive goals that had been set under the Senior Executive Plan. Based upon this performance, the ATLS compensation committee recommended that ATLS award cash incentive bonuses to our NEOs as follows: Edward E. Cohen, $5,000,000 and Jonathan Z. Cohen, $4,000,000. The aggregate annual incentive awards were less than the maximum amount payable to each of the NEOs pursuant to the predetermined percentages established under the Senior Executive Plan, which were as follows: Edward E. Cohen, $28,818,000 and Jonathan Z. Cohen, $20,510,000.

Discretionary Bonuses. Messrs. Dubay, Kalamaras and Shrader are not participants in the Senior Executive Plan. The AHD compensation committee awarded them discretionary bonuses as follows: Mr. Dubay-$1,000,000, Mr. Kalamaras-$180,000 and Mr. Shrader-$215,000. Among other factors, the discretionary bonuses were awarded based on performance in connection with the sale of Elk City and the execution of our new credit facility.

APLMC Plan Awards. The Atlas Pipeline Mid-Continent Plan (the APLMC Plan) specifically prohibits awards to anyone who is an NEO at the time of the grant. Mr. Shrader received awards under the APLMC Plan, but was granted those awards prior to becoming a NEO. In addition, upon execution of his employment agreement with ATLS in September 2009, Mr. Kalamaras was awarded 50,000 bonus units on substantially the same terms as the bonus units under the APLMC Plan. No additional grants to our NEOs can be made under the APLMC Plan. Each of Messrs. Shrader and Kalamaras exchanged their bonus units for phantom units, effective June 1, 2010, in connection with the approval of the 2010 Plan.

The following table sets forth the compensation allocation for fiscal years 2010, 2009 and 2008 for our General Partner s Chief Executive Officer and Chief Financial Officer 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 table also discloses awards under the AHD Plan and the ATLS Plans.

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Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Stock Awards(1)	Option Awards(1)	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Eugene N. Dubay,	2010	$ 500,000	$ 1,000,000	$ 1,334,009	$ 1,008,700	$	$ 26,338(2)	$ 3,869,047
Chief Executive Officer and President	2009	438,847	500,000		564,000		555,805	2,058,652
Eric T. Kalamaras,	2010	274,519	180,000	244,640	273,790		49,425(3)	1,022,374
Chief Financial Officer	2009	157,000	152,917	66,620				376,537
Edward E. Cohen,	2010	150,000				750,000	3,375(4)	903,375
	2009	147,577				375,000	12,600	535,177
Chairman of the Board	2008	135,000					257,938	392,938
Jonathan Z. Cohen,	2010	105,000				600,000	1,688(4)	706,688
	2009	101,539				300,000	7,863	409,402
Vice Chairman of Atlas Pipeline GP	2008	90,000					113,488	203,488
Gerald R. Shrader,	2010	274,519	215,000	244,640			19,600(2)	753,759
Chief Legal Officer	2009	224,616	300,000	96,000				620,616

(1) See Item 8. Financial Statements and Supplementary Data Note 16 for further discussion regarding assumptions made in valuation of fair value on grant date.

(2) Includes payments of DERs with respect to the phantom units awarded under our 2004 and 2010 Plans.

(3) Includes (i) relocation expense of $30,000 and (ii) payments of DERs with respect to phantom units awarded under our 2010 Plan.

(4) Includes payments of DERs with respect to phantom units awarded under the AHD 2006 Plan.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

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

Mr. Cohen s employment agreement required him to devote such time to ATLS 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 ATLS 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.

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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 employment agreement was entered into in 2004, around the time that ATLS 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 ATLS. 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.

ATLS 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 ATLS s employees, during the three years following his termination, (c) a lump sum amount equal to the cost ATLS 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 ATLS s long-term disability plan.

ATLS 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 ATLS s Board of Directors or ATLS s material breach of the agreement. Mr. Cohen must provide ATLS with 30 days notice of a termination by him for good reason within 60 days of the event constituting good reason. ATLS 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 ATLS 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 ATLS 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 ATLS s employees, during the three years following his termination, (iii) a lump sum amount equal to the cost ATLS would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by ATLS 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 ATLS, 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.

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Change of control is defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act of 1933, of 25% or more of ATLS s voting securities or all or substantially all of ATLS 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;

- ATLS consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) ATLS 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 ATLS s directors immediately before the transaction and ATLS s chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) ATLS s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of ATLS, 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 ATLS Board members at the beginning of the period cease for any reason to constitute a majority of the ATLS Board, unless the election or nomination for election by ATLS 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

- ATLS s stockholders approve a plan of complete liquidation or winding up of ATLS, or agreement of sale of all or substantially all of ATLS s assets or all or substantially all of the assets of ATLS 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, ATLS 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.

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 if a termination event had occurred as of December 31, 2010.

Reason for Termination	Lump Sum Severance Payment	Benefits[(1)]	Accelerated Vesting of option awards[(2)]	Tax Gross-up[(3)]
Death	$ 450,000[(4)]	$	$	$
Disability	450,000[(4)]	6,576		
Termination by us without cause or by Mr. Cohen for good reason	3,432,577[(5)]	6,576		
Change of control	3,432,577[(5)]	6,576		984,005
Termination by Mr. Cohen without cause	75,000[(4)]			

(1) Represents rates currently in effect for COBRA insurance benefits for 36 months.

(2) Mr. Cohen had no outstanding unexercisable options or unvested unit awards under our Plans or the AHD Plans as of the year ended December 31, 2010.

(3) Calculated after deduction of any excise tax imposed under section 4999 of the Code, and any federal, state and local income tax, FICA and Medicare withholding taxes, taking into account the 20% excess parachute payment rate and a 36.45% combined effective tax rate.

(4) Calculated based on Mr. Cohen s 2010 base salary.

(5) Calculated based on Mr. Cohen s average 2010, 2009 and 2007 base salary and bonus.

Jonathan Z. Cohen

In January 2009, ATLS entered into an employment agreement with Jonathan Z. Cohen, who currently serves as our Vice-Chairman. As discussed above under Compensation Discussion and Analysis, ATLS allocated a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. Mr. Cohen s employment agreement terminated in February 2011, in connection with the Chevron Merger. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that were allocated in part to us.

Mr. Cohen s employment agreement required him to devote such time to ATLS 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 ATLS 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.

ATLS 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 ATLS s board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by ATLS 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 ATLS of the employment agreement or a

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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.

ATLS 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 ATLS 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 is defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 25% or more of ATLS s voting securities or all or substantially all of ATLS 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;

ATLS consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) ATLS 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 ATLS s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) ATLS s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of ATLS, 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 ATLS board members at the beginning of the period cease for any reason to constitute a majority of ATLS s board, unless the election or nomination for election by ATLS 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

ATLS s stockholders approve a plan of complete liquidation or winding up, or agreement of sale of all or substantially all of ATLS 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. 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

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activities during the prior three-year period. The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2010.

Reason for Termination	Lump Sum Severance Payment	Benefits(1)	Accelerated Vesting of unit and option awards(2)
Death	$	$	$
Termination by us other than for cause (including disability) or by Mr. Cohen for good reason (including a change of control)	1,290,000(3)		
Termination by us for cause or by Mr. Cohen for other than good reason			

(1) Mr. J. Cohen did not receive benefits from ATLS.

(2) Mr. J. Cohen had no outstanding unexercisable options or unvested unit awards under our Plans or the AHD Plans as of the year ended December 31, 2010.

(3) Calculated based on Mr. J. Cohen s average 2010 base salary and cash bonus for 2010, 2009 and 2008.

Eugene N. Dubay

In January 2009, ATLS entered into an employment agreement with Eugene N. Dubay, who currently serves as our President and Chief Executive Officer. Mr. Dubay s employment agreement terminated in February 2011, in connection with the Chevron Merger. As discussed above under Compensation Discussion and Analysis, ATLS allocated all of Mr. Dubay s compensation cost to us and AHD.

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 were awarded solely at the discretion of ATLS 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 ATLS agreed to purchase his residence in Michigan for $1,000,000. Upon execution of the agreement, Mr. Dubay was granted the following equity compensation:

- Options to purchase 100,000 shares of ATLS 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 AHD 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. ATLS could 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 our and Atlas Pipeline Holding s board of directors determine, in good faith based upon medical evidence, that he is unable to perform his duties;

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 is only effective if such failure has not been cured within 90 days after notice is given to ATLS. 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 is defined as (a) the commitment of a material act of fraud, (b) illegal or gross misconduct that is willful and results in damage to our business or reputation, (c) being charged with a felony, (d) continued failure by Mr. Dubay to perform his duties after notice other than as a result of physical or mental illness, or (e) Mr. Dubay s failure to follow ATLS s reasonable written directions consistent with his duties. Good reason is defined as any action or inaction that constitutes a material breach by ATLS of the agreement or a change of control. Change of control is defined as:

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

ATLS consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction of ATLS other than with a related entity, in which either (a) ATLS 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 ATLS directors immediately before the transaction and ATLS s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) ATLS s voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of ATLS, 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 ATLS board members at the beginning of the period cease for any reason to constitute a majority of ATLS s board, unless the election or nomination for the election by ATLS 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

ATLS s shareholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of ATLS s assets or all or substantially all of the assets of its primary subsidiaries other than to a related entity.

The agreement provided the following regarding termination and termination benefits:

Upon termination of employment due to death, Mr. Dubay s designated beneficiaries will receive a lump sum cash payment within 60 days of the date of death of (a) any unpaid portion of his annual salary earned and not yet paid, (b) an amount representing the incentive compensation earned for the period up to the date of termination computed by assuming that

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all such incentive compensation would be equal to the amount of incentive compensation Mr. Dubay earned during the prior fiscal year, pro-rated through the date of termination; and (c) any accrued but unpaid incentive compensation and vacation pay.

Upon termination of employment by ATLS other than for cause, including disability, or by Mr. Dubay for good reason, if Mr. Dubay executes and does not revoke a release, Mr. Dubay will receive (a) pro-rated cash incentive compensation for the year of termination, based on actual performance for the year; and (b) monthly severance pay for the remainder of the employment term in an amount equal to 1/12 of (x) his annual base salary and (y) the annual amount of cash incentive compensation paid to Mr. Dubay for the fiscal year prior to his year of termination; (c) monthly reimbursements of any COBRA premium paid by Mr. Dubay, less the monthly premium charge paid by employees for such coverage; and (d) automatic vesting of all equity awards.

Upon Mr. Dubay s termination from employment by ATLS for cause or by Mr. Dubay for any reason other than good reason, Mr. Dubay will receive his accrued but unpaid base salary.

Mr. Dubay is also subject to a non-solicitation covenant for two years after any termination of employment and, in the event his employment is terminated by ATLS for cause, or terminated by him for any reason other than good reason, a non-competition covenant not to engage in any natural gas pipeline and/or processing business in the continental United States for 18 months.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. We anticipate that lump sum termination amounts paid to Mr. Dubay would be allocated to us consistent with past practice. The following table provides an estimate of the value of the benefits to Mr. Dubay if a termination event had occurred as of December 31, 2010.

Reason for Termination	**Lump Sum Severance Payment**	**Benefits**	**Accelerated Vesting of unit and option awards[(1)]**
Death	$	$	$ 8,512,379
Termination by ATLS other than for cause (including disability) or by Mr. Dubay for good reason (including a change of control)	1,083,333[(2)]	18,442	8,512,379

(1) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2010. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2010.

(2) Calculated based on Mr. Dubay s average 2010 base salary and bonus.

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Eric T. Kalamaras

In September 2009, ATLS entered into a letter agreement with Eric Kalamaras, who currently serves as our Chief Financial Officer. Mr. Kalamaras employment agreement terminated in February 2011 in connection with the Chevron Merger. As discussed above under Compensation Discussion and Analysis, ATLS allocated all of Mr. Kalamaras compensation cost to us and AHD.

The agreement provided for an annual base salary of $250,000, a one-time cash signing bonus of $80,000 and a one-time award of 50,000 equity-indexed bonus units which entitled Mr. Kalamaras, upon vesting, to receive a cash payment equal to the fair market value of our common units. Mr. Kalamaras exchanged the bonus units for phantom units, effective June 1, 2010, in connection with the approval of the 2010 Plan, which vest 25% per year.

Mr. Kalamaras was also eligible for discretionary annual bonus compensation in an amount not to exceed 100% of his annual base salary and participation in all employee benefit plans in effect during his employment. The agreement provided that Mr. Kalamaras would serve as an at-will employee.

The agreement provided the following regarding termination and termination benefits:

- ATLS may terminate Mr. Kalamaras employment for any reason upon 30 days prior written notice, or immediately for cause.

- Mr. Kalamaras may terminate his employment for any reason upon 60 days prior written notice.

- Upon termination of employment for any reason, Mr. Kalamaras will receive his accrued but unpaid annual base salary through his date of termination and any accrued and unpaid vacation pay.

Cause is defined as having (a) committed an act of malfeasance or wrongdoing affecting the company or its affiliates, (ii) breached any confidentiality, non-solicitation or non-competition covenant or employment agreement or (iii) otherwise engaged in conduct that would warrant discharge from employment or service because of his negative effect on the company or its affiliates. Change of control means the acquisition by a person or group of (i) more than 50% of the total value of ownership interests or voting interests in Atlas Pipeline Mid-Continent, LLC or APL or (ii) during any 12 month period, assets of either company having a total gross fair market value equal to more than 50% of the total gross fair market value of the assets of the affected company.

Mr. Kalamaras is also subject to a confidentiality and non-solicitation agreement for 12 months after any termination of employment. 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.

Our Long-Term Incentive Plans

Our 2004 Long-Term Incentive Plan (the 2004 Plan) and the 2010 Long-Term Incentive Plan (the 2010 Plan and collectively with the 2004 Plan the Plans) provide incentive awards to officers, employees and non-employee managers of our General Partner and officers and employees of our General Partner s affiliates, consultants and joint venture partners who perform services for us or in furtherance of our business. Our Plan is administered by our General Partner s managing board or the board of an affiliate appointed by it (the Committee). Under the Plans, the Committee may make awards of either phantom units or options covering an aggregate of 435,000 common units under the 2004 Plan and 3,000,000 common units under the 2010 Plan.

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

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

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

Atlas Pipeline Partners GP (or an affiliate of ATLS) ceasing to be our General Partner;

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

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

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

Under the 2010 LTIP, both types of awards will automatically vest upon a change of control, defined as follows:

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- Atlas Pipeline Partners GP, LLC or an affiliate ceases to be our general partner;

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

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

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

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

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

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

Employee Incentive Compensation Plan and Agreement

The APLMC Plan, adopted in June 2009, allows for equity-indexed cash incentive awards to personnel who perform services for us (the Participants), but expressly excludes as an eligible Participant any of our NEO s (as such term is defined under the rules of the Securities and Exchange Commission) at the time of the award. The APLMC Plan is administered by a committee appointed by our chief executive officer. Under the APLMC Plan, cash bonus units may be awarded Participants at the discretion of the committee, Bonus units totaling 325,000 were awarded under the Incentive Plan during the year ended December 31, 2009. In September 2009, Mr. Kalamaras was separately awarded 50,000 bonus units on substantially the same terms as the bonus units available under the APLMC Plan (the bonus units issued under the Incentive Plan and under the separate agreement are, for purposes hereof, referred to as 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. Each of Messrs. Shrader and Kalamaras exchanged their bonus units for phantom units, effective June 1, 2010, in connection with the approval of the 2010 Plan.

AHD Plans

The AHD 2006 Long-Term Incentive Plan (the AHD 2006 Plan) and the AHD 2010 Long-Term Incentive Plan (the AHD 2010 Plan and collectively with the 2006 AHD Plan the AHD Plans) provides equity incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners who perform services for AHD. The AHD Plans are administered by the board of AHD s general partner or the board of an affiliate appointed by AHD s board (the AHD Committee). The AHD Committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 AHD common limited partner units for the AHD 2006 Plan and an aggregate of 5,300,000 AHD common limited partner units for the AHD 2010 Plan. Pursuant to the employee matters agreement AHD entered into in connection with the AHD Transactions (See Item 1: Business Recent Developments), AHD amended the AHD 2006 Plan to provide that outstanding awards granted under AHD 2006 Plan did not vest in connection with the Chevron Merger and the AHD Transactions pursuant to the terms and conditions of the 2006 Plan.

Partnership Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Beginning in fiscal year 2010, non-employee directors receive an annual grant of phantom units having a market value of $25,000, which, upon vesting, entitle the grantee to receive the equivalent number of AHD common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the AHD Committee may grant a DER. The AHD Committee determines the vesting period for phantom units. Phantom units granted under the 2006 AHD Plan generally vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant, except non-employee director grants vest 25% per year.

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

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

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

As required by SEC guidelines, the following tables disclose awards under our Plans as well as under the AHD Plans and the Atlas Plans.

GRANTS OF PLAN-BASED AWARDS

Name	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)	Grant Date Fair Value of Unit and Option Awards
Eugene N. Dubay	02/08/2010	17,212(1)		$	$ 500,009
	02/08/2010		70,000(2)	29.05	1,008,700
	06/22/2010	75,000(3)(4)			834,000
Eric T. Kalamaras	02/08/2010		19,000(2)	29.05	273,790
	06/22/2010	22,000(3)			244,640
Gerald R. Shrader	06/22/2010	22,000(3)			244,640

(1) Represents restricted units granted under the ATLS 2009 Plan, which vested upon completion of the Chevron Merger. The weighted average price for restricted unit awards on the date of grant, which is utilized in the calculation of compensation expense, was $29.05.

(2) Represents options granted under the ATLS 2009 Plan, which vested upon completion of the Chevron Merger. 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 $14.41.

(3) Represents phantom units granted under our 2010 Plan. The weighted average price for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense, was $11.12.

(4) Vested upon completion of the Chevron Merger.

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OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options		Option Exercise Price	Option Expiration Date	Number of Units that have not Vested	Market Value of Units that have not Vested
	Exercisable	Unexercisable				
Eugene N. Dubay		75,000[1]	$ 6.24	01/15/2019	75,250[2]	$ 1,856,417[3]
		100,000[4]	3.24	01/15/2019		
		75,000[5]	13.35	01/15/2019		
		70,000[6]	29.05	02/08/2020	17,212[7]	756,812[8]
Eric T. Kalamaras		19,000[9]	29.05	02/08/2020	55,500[10]	1,369,185[3]
Edward E. Cohen	500,000[11]		22.56	11/10/2016		
Jonathan Z. Cohen	200,000[11]		22.56	11/10/2016		
Gerald R. Shrader					56,000[12]	1,381,520[3]

(1) Represents options to purchase our common units, which vested as follows: 01/15/11 25,000; 02/17/11 50,000.
(2) Represents our phantom units, which vested on 02/17/11
(3) Based on closing market price of our common units on December 31, 2010 of $24.67.
(4) Represents options to purchase AHD units, which vested on 02/17/11.
(5) Represents options to purchase ATLS common stock, which vested as follows: 01/15/11 25,000; and 2/17/11 50,000.
(6) Represents options to purchase ATLS common stock, which vested as follows: 02/08/11 17,500; and 2/17/11 52,500.
(7) Represents ATLS phantom units, which vested as follows: 02/08/11 4,303; and 2/17/11 12,909.
(8) Based on closing market price of ATLS s common stock on December 31, 2010 of $43.97.
(9) Represents options to purchase ATLS common stock, which vested as follows: 02/08/11 4,750; and 2/17/11 14,250.
(10) Represents our phantom units, which vest as follows: 06/22/11 5,500; 09/14/11 16,500; 06/22/12 5,500; 09/14/12 17,000; 06/22/13 5,500 and 06/22/14 5,500.
(11) Represents options to purchase AHD units.
(12) Represents our phantom units, which vest as follows: 03/03/11 250; 06/01/11 16,500; 06/22/11 5,500; 03/03/12 250; 06/01/12 17,000; 06/22/12 5,500; 06/22/13 5,500 and 06/22/14 5,500.

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2010 OPTION EXERCISES AND STOCK VESTED TABLE

	Option Awards		Stock Awards	
	Number of Units Acquired on Exercise	Value Realized on Exercise	Number of Units Acquired on Vesting	Value Realized on Vesting(1)
Eugene E. Dubay	50,000(2)	$ 941,484	125(3)	$ 2,436
Eric T. Kalamaras			16,500(3)	305,580
Edward E. Cohen			72,500(4)	997,050
Jonathan Z. Cohen			37,500(5)	523,350
Gerald R. Shrader			16,750(3)	162,418

(1) Value realized on vesting is based upon market price on date of vesting.
(2) Represents 25,000 shares of ATLS common stock with an intrinsic value of $486,564 and 25,000 of our common units with an intrinsic value of $454,920 (See Item 8. Financial Statements and Supplementary Data Note 16).
(3) Represents our common units.
(4) Represents 67,500 common units of AHD and 5,000 of our common units.
(5) Represents 33,750 common units of AHD and 3,750 of our common units.

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash	Stock Awards	All Other Compensation(1)	Total
Tony C. Banks	$ 100,000(2)	$ 24,984(3)	$ 761	$ 125,745
Curtis D. Clifford	80,000(4)	25,393(5)	743	106,136
Martin Rudolph	95,000(6)	24,990(7)	740	120,731
Michael Staines(8)	29,121	24,998(9)	559	54,677

(1) Represents payments on DERs for phantom units.
(2) Includes $50,000 for service on the special committee chairman regarding the Laurel Mountain sale.
(3) Represents 500 phantom units having a grant date fair value of $11.16 and 1,050 phantom units having a grant date fair value of $18.48, granted under our Plan. The phantom units vest 25% on each anniversary of the date of grant as follows: 2/11/11 125; 10/07/11 262; 2/11/12 125; 10/07/12 262; 2/11/13 125; 10/07/13 262; 2/11/14 125 and 10/07/14 262.
(4) Includes $30,000 for service on the special committee regarding the Laurel Mountain sale.
(5) Represents 500 phantom units having a grant date fair value of $13.90 and 998 phantom units having a grant date fair value of $18.48, granted under our Plan. The phantom units vest 25% on each anniversary of the date of grant as follows: 5/10/11 125; 10/07/11 249; 5/10/12 125; 10/07/12 249; 5/10/13 125; 10/07/13 249; 5/10/14 125 and 10/07/14 251.
(6) Includes $30,000 for service on the special committee regarding the Laurel Mountain sale and $15,000 for service as the Audit Committee Chairman.
(7) Represents 500 phantom units having a grant date fair value of $14.24 and 967 phantom units having a grant date fair value of $18.48, granted under our Plan. The phantom units vest 25% on each anniversary of the date of grant as follows: 3/17/11 125; 10/07/11 241; 3/17/12 125; 10/07/12 241; 3/17/13 125; 10/07/13 241; 3/17/14 125 and 10/07/14 244.
(8) Mr. Staines resigned from employment with ATLS as of July 2009 and as part of his separation arrangement, he did not receive a director s fee until July 2010.
(9) Represents 500 phantom units having a grant date fair value of $9.45 and 1,097 phantom units having a grant date fair value of $18.48, granted under our Plan. The phantom units vest 25% on each anniversary of the date of grant as follows: 7/01/11 125; 10/07/11 274; 7/01/12 125; 10/07/12 274; 7/01/13 125; 10/07/13 274; 7/01/14 125 and 10/07/14 275.

Our General Partner did not pay additional remuneration to officers or employees of ATLS who also served as managing board members. In fiscal year 2010, each non-employee managing board member received an annual retainer of $50,000 in cash (which was increased from $35,000 in October 2010 effective retroactively to January 1, 2010), and an annual grant of phantom units pursuant to our Long-Term Incentive

Plan having a market value of $25,000 (which was increased in October 2010 effective retroactively to January 1, 2010 from an award of phantom units with DERs in an amount equal to the lesser of 500 units or $15,000 worth of units (based upon the market price of our common units)). In October 2010, the general partner authorized the grant of additional phantom units under the Long-Term Incentive Plan to each non-employee managing board member for the 2009 calendar year because due to the previous limitation of each award to a maximum of 500 phantom units, the target of $15,000 in phantom unit awards for the 2009 calendar year was not achieved. The additional make-up grants for the 2009 calendar year vest over four years and were made to the non-employee managing board member on the next annual vesting date occurring after November 1, 2010. In addition, in April 2010, the Board authorized payment to the Chairman of the Audit Committee in the amount of $15,000 in cash (effective January 1, 2010).

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

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

The following table sets forth the number and percentage of shares of common stock owned, as of February 22, 2011 by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding shares of common stock, (b) each of the members of the managing board of our General Partner, (c) each of the executive officers named in the Summary Compensation Table in Item 11, and (d) all of the named executive officers and board members as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person. The address of our General Partner, its executive officers and managing board members is 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108.

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Name of Beneficial Owner	Common Unit Amounts and Nature of Beneficial Ownership	Percent of Class
Executive Officers and Members of the Managing Board		
Eugene N. Dubay	174,500 (1)	*
Eric T. Kalamaras	10,967	*
Edward E. Cohen	89,200	*
Jonathan Z. Cohen	53,477	*
Gerald R. Shrader	17,250 (2)	*
Robert W. Karlovich III	6,364 (2)	*
Tony C. Banks	1,786	*
Curtis D. Clifford	2,460	*
Gayle P. W. Jackson	2,050	
Martin Rudolph	2,147 (3)	*
Matthew A. Jones	20,000	*
Michael L. Staines	12,000	*
Executive officers and Managing Board Members as a group (12 persons)	392,201	*
Other Owners of More than 5% of Outstanding Units		
Atlas Energy, L.P.	4,113,227	7.7%
Leon Cooperman	5,119,818 (4)	9.6%
FMR LLC	4,685,342 (5)	8.8%
MSD Capital, L.P.	3,500,000 (6)	6.6%

* Less than 1%.

(1) Includes 75,000 vested unit options granted under our 2004 Plan pursuant to the terms of Mr. Dubay s employment agreement on January 15, 2009. Each unit option represents the right to purchase one common unit.

(2) Includes 250 phantom units granted pursuant to our 2004 Plan which will vest on March 3, 2011. Each phantom unit represents the right to receive, upon vesting, one common unit.

(3) Includes 426 phantom units granted pursuant to our 2004 Plan which will vest on March 17, 2011. Each phantom unit represents the right to receive, upon vesting, one common unit.

(4) This information is based upon a Schedule 13G/A which was filed with the SEC on February 3, 2011. The address for Mr. Cooperman is 88 Pine Street, Wall Street Plaza 31st Floor, New York, NY 10005.

(5) This information is based upon a Schedule 13G/A which was filed with the SEC on February 14, 2011. The address for FMR LLC is 82 Devonshire Street, Boston, MA 02109.

(6) This information is based upon a Schedule 13G which was filed with the SEC on January 31, 2011. The address for MSD Capital, LP is 645 Fifth Avenue, 21st Floor, New York, New York 10022.

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Equity Compensation Plan Information

The following table contains information about our 2004 Plan as of December 31, 2010:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units	24,774	n/a	
Equity compensation plans approved by security holders unit options	75,000	$ 6.24	
Equity compensation plans approved by security holders Total	99,774		66,459

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

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units	466,112	n/a	
Equity compensation plans approved by security holders Total	466,112		2,434,888

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The following table contains information about the AHD 2006 Plan as of December 31, 2010:

Plan category		Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units		27,294	n/a	
Equity compensation plans approved by security holders	unit options	955,000	$ 20.54	
Equity compensation plans approved by security holders	Total	982,294		940,556

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

Plan category		Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units			n/a	
Equity compensation plans approved by security holders	unit options		$	
Equity compensation plans approved by security holders Total				3,500,000

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The following table contains information about ATLS s Plans as of December 31, 2010:

Plan category		Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units		579,189	n/a	
Equity compensation plans approved by security holders unit options		4,536,670	$ 21.01	
Equity compensation plans approved by security holders	Total	5,115,859		3,664,188

The following table contains information about ATLS s Assumed Plan from Atlas Energy Resources as of December 31, 2010:

Plan category		Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders phantom units		674,598	n/a	
Equity compensation plans approved by security holders unit options		1,990,151	$ 20.35	
Equity compensation plans approved by security holders	Total	2,664,749		n/a

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

We do not directly employ any persons to manage or operate our business. These functions are provided by our General Partner and employees of ATLS. Our General Partner does not receive a management fee in connection with its management of our operations, but we reimburse our General Partner and its affiliates for compensation and benefits related to ATLS employees who perform services to us, based upon an estimate of the time spent by such persons on our activities. Other indirect costs, such as rent for offices, are allocated to us by ATLS based on the number of its employees who devote substantially all of their time to our activities. Our partnership agreement provides that our General Partner will determine the costs and expenses that are allocable to us in any reasonable manner determined at its sole discretion. We reimbursed our General Partner and its affiliates $1.5 million for the year ended December 31, 2010 for compensation and benefits related to their employees. Our General Partner believes that the method utilized in allocating costs to us is reasonable.

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

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

Each of Messrs. E. Cohen, J. Cohen and Dubay were determined to be related parties with respect to the Laurel Mountain Sale (See Item 1: Business Recent Developments). None of Messrs. E. Cohen, J. Cohen or Dubay participated in the approval of the Laurel Mountain Sale on our behalf.

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

On February 17, 2011, ATLS consummated its merger with Chevron pursuant to the Chevron Merger Agreement whereby ATLS became a wholly-owned subsidiary of Chevron. Additionally, on February 17, 2011, AHD consummated the AHD Transactions with ATLS and Atlas Energy Resources. Subsequent to these transactions, AHD s general partner will employ the individuals who manage and operate our business. See Item 1: Business Recent Developments for further discussion.

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ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ended December 31, 2010 and 2009 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2010	2009
Audit fees [1]	$ 1,507,317	$ 1,635,120
Audit related fees[2]		100,500
Tax fees [3]	105,492	120,157
All other fees		
Total aggregate fees billed	$ 1,612,809	$ 1,855,777

(1) Represents the aggregate fees recognized in 2010 and 2009 for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements, the review of financial statements included in Form 10-Q and the review of registration statements and Form 8-Ks.

(2) Fees are for services that are normally provided by Grant Thornton LLP in connection with statutory or regulatory filings or engagements.

(3) Represents the fees recognized in each 2010 and 2009 for professional services rendered by Grant Thornton LLP for tax compliance, tax advice, and tax planning.

Audit Committee Pre-Approval Policies and Procedures

Pursuant to its charter, the audit committee of the managing board of our General Partner is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. All of such services and fees were pre-approved during 2010 and 2009.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Financial Statements

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

(2) Financial Statement Schedules

No schedules are required to be presented.

(3) Exhibits:

Exhibit No.	Description
2.1	Securities Purchase Agreement, dated July 27, 2010, by and among Atlas Pipeline Mid-Continent, LLC, Atlas Pipeline Partners, L.P., Enbridge Pipelines (Texas Gathering) L.P. and Enbridge Energy Partners, L.P.[23]
2.2	Purchase and Sale Agreement, by and among Atlas Pipeline Partners, L.P., APL Laurel Mountain, LLC, Atlas Energy, Inc., and Atlas Energy Resources, LLC, dated November 8, 2010. [24]
3.1	Certificate of Limited Partnership[1]
3.2(a)	Second Amended and Restated Agreement of Limited Partnership[2]
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership[3]
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership[4]
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership[6]
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership[7]
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership[11]
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership[13]
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership[25]
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership[26]
4.1	Common unit certificate[1]
4.2(a)	8 1/8% Senior Notes Indenture dated December 20, 2005[12]
4.2(b)	Supplemental Indenture dated November 22, 2010[27]
4.3	8 3/4% Senior Notes Indenture dated June 27, 2008[9]
4.4	Certificate of Designation for 12% Cumulative Class C Preferred Units of Atlas Pipeline Partners, L.P. [30]
10.1	Amended and Restated Credit Agreement dated July 27, 2007, amended and restated as of December 22, 2010, by and among Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the several guarantors and lenders hereto[28]

10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[29]
10.3	Form of Warrant to purchase common units dated August 20, 2009[15]
10.4	Form of First Amendment to Warrant to purchase common units dated January 7, 2010[22]
10.5	Long-Term Incentive Plan[35]
10.6	2010 Long-Term Incentive Plan[31]
10.7	Form of Grant of Phantom Units in Exchange for Bonus Units[31
10.8	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter[32]
10.9	Form of Grant of Phantom Units to Non-Employee Managers[33]
10.10	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan[35]
10.11	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement[35]
10.12	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay[17]
10.13	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras[21]
10.14	Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009[21]

10.15	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010[24]
10.16	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010[34]
10.17	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[34]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Grant Thornton LLP
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 29, 2009.
(6) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(8) [Intentionally Omitted]
(9) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.
(10) [Intentionally Omitted]
(11) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(12) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.
(13) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(14) [Intentionally Omitted]
(15) Previously filed as an exhibit to current report on Form 8-K on August 20, 2009.
(16) [Intentionally Omitted]
(17) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
(18) [Intentionally Omitted]
(19) [Intentionally Omitted]
(20) [Intentionally Omitted]
(21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
(22) Previously filed as an exhibit to current report on Form 8-K on January 8, 2010.
(23) Previously filed as an exhibit to current report on Form 8-K on July 29, 2010.
(24) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
(25) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
(26) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
(27) Previously filed as an exhibit to current report on Form 8-K on November 26, 2010.
(28) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
(29) Previously filed as an exhibit to current report on Form 8-K filed on April 2, 2010.
(30) Previously filed as an exhibit to current report on Form 8-K filed on July 7, 2010.
(31) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
(32) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
(33) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
(34) Previously filed as an exhibit to Atlas Energy, Inc. s current report on Form 8-K filed on November 12, 2010.
(35) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.

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SIGNATURES

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

ATLAS PIPELINE PARTNERS, L.P.
By: Atlas Pipeline Partners GP, LLC,

its General Partner

February 25, 2011

By: /s/ EUGENE N. DUBAY
Chief Executive Officer, President and Managing Board Member of the General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 25, 2011.

/s/ EDWARD E. COHEN **Edward E. Cohen**	Chairman of the Managing Board of the General Partner
/s/ JONATHAN Z. COHEN **Jonathan Z. Cohen**	Vice Chairman of the Managing Board of the General Partner
/s/ EUGENE N. DUBAY **Eugene N. Dubay**	Chief Executive Officer, President and Managing Board Member of the General Partner
/s/ ERIC T. KALAMARAS **Eric T. Kalamaras**	Chief Financial Officer of the General Partner
/s/ ROBERT W. KARLOVICH III **Robert W. Karlovich III**	Chief Accounting Officer of the General Partner
/s/ TONY C. BANKS **Tony C. Banks**	Managing Board Member of the General Partner
/s/ CURTIS D. CLIFFORD **Curtis D. Clifford**	Managing Board Member of the General Partner
/s/ GAYLE P.W. JACKSON **Gayle P.W. Jackson**	Managing Board Member of the General Partner
/s/ MARTIN RUDOLPH	Managing Board Member of the General Partner

Martin Rudolph

/s/	MICHAEL L. STAINES	Managing Board Member of the General Partner

Michael L. Staines

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