ATLAS PIPELINE PARTNERS LP
Form 10-K
February 29, 2008
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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, 2007

OR

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

For the transition period from ______ to ______

Commission file number: 1-14998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1550 Corapolis 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

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 $54.27 per common limited partner unit on June 30, 2007, was approximately $620.8 million.

DOCUMENTS INCORPORATED BY REFERENCE: None

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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 price volatility and demand for natural gas and natural gas liquids;*
- *our ability to connect new wells to our gathering systems;*
- *our ability to integrate newly acquired businesses with our operations;*
- *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.

PART I

ITEM 1. BUSINESS

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 services in the Anadarko, Arkoma, Golden Trend and Permian Basins in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas and southeastern Missouri. We conduct our business in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

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Through our Mid-Continent operations, we own and operate:

- a Federal Energy Regulatory Commission (FERC)-regulated, 565-mile interstate pipeline system (Ozark Gas Transmission), that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and has throughput capacity of approximately 400 million cubic feet per day (MMcfd);

- seven natural gas processing plants with aggregate capacity of approximately 750 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and

- 7,870 miles of active natural gas gathering systems located in Oklahoma, Arkansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or Ozark Gas Transmission.

Through our Appalachian operations, we own and operate 1,600 miles of active natural gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Through an omnibus agreement and other agreements between us and Atlas America, Inc. (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

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 2% general partner interest. Atlas Pipeline GP is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly traded Delaware limited partnership (NYSE: AHD).

Since our initial public offering in January 2000, we have completed seven acquisitions at an aggregate purchase price of approximately $2.4 billion, including most recently:

- On July 27, 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering system 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 (the Anadarko Assets). The Chaney Dell system includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. In connection with this acquisition, we reached an agreement with Pioneer Natural Resources Company (Pioneer NYSE: PXD), which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer will have an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008, and up to an additional 7.4% interest beginning on June 15, 2009. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options. We funded the purchase price in part from our private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. Our general partner, which holds all of our incentive distribution rights, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. We funded the remaining purchase price from an $830.0 million senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013; and

In May 2006, we acquired the remaining 25% ownership interest in NOARK Pipeline System, Limited Partnership (NOARK) from Southwestern Energy Company (Southwestern) for a net purchase price of $65.5 million, consisting of $69.0 million in cash to the seller, (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in working capital at the date of acquisition of $3.5 million. In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owned the initial 75% ownership interest in NOARK, for $163.0 million, plus $16.8 million for working capital adjustments and related transaction costs. NOARK s principal assets include the Ozark Gas Transmission system, a 565-mile interstate natural gas pipeline, and Ozark Gas Gathering, a 365-mile natural gas gathering system.

Both our Mid-Continent and Appalachian operations are located in areas of abundant and long-lived natural gas production and significant new drilling activity. The Ozark Gas Transmission system, which is a part of the NOARK system, and our gathering systems are connected to approximately 7,300 central delivery points or wells, giving us significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. We provide fee-based, FERC-regulated transmission services through Ozark Gas Transmission under both long-term and short-term contractual arrangements. As a result of the location and capacity of the Ozark Gas Transmission system and our gathering and processing assets, we believe that we are strategically positioned to capitalize on the significant increase in drilling activity in our service areas and the positive price differential across Ozark Gas Transmission, also known as basis spread. We intend to continue to expand our business through strategic acquisitions and internal growth projects that increase distributable cash flow.

The Midstream Natural Gas Gathering, Processing and Transmission 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 small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells.

While natural gas produced in some areas, such as the Appalachian Basin, does not require treatment or processing, natural gas produced in many other areas, such as our Velma service area in Oklahoma, is not suitable for long-haul pipeline transmission or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components such as NGLs and other contaminants that would interfere with pipeline transmission or the end use of the natural gas. Natural gas processing plants generally treat (remove carbon dioxide and hydrogen sulfide) and remove the NGLs, enabling the treated, dry gas (stripped of liquids) 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 on pipelines to a centralized facility for fractionation into discrete NGL purity products: ethane, propane, normal butane, isobutane, and natural gasoline.

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Natural gas transmission pipelines receive natural gas from producers, other mainline transmission 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 transmission 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 transportation and sale of natural gas and NGLs. Variables that affect our revenue are:

- the volumes of natural gas we gather, transport 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 and NGLs; and

- the transportation and processing fees we receive which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has exceeded this minimum generally. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, 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, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas received by our Elk City/Sweetwater and Chaney Dell systems, which have keep-whole contracts, is generally low in liquids content and meets 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. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

Our Mid-Continent Operations

We own and operate a 565-mile interstate natural gas pipeline, approximately 8,670 miles of intrastate natural gas gathering systems, including approximately 800 miles of inactive pipeline, located in Oklahoma, Arkansas, southeastern Missouri, northern and western Texas and the Texas panhandle, and seven processing plants and one stand-alone treating facility in Oklahoma and Texas. Ozark Gas Transmission transports natural gas from receipt points in eastern Oklahoma, including major intrastate pipelines, and western Arkansas, where the Arkoma Basin is located, to local distribution companies in Arkansas and Missouri and to interstate pipelines in northeastern and central Arkansas. Our gathering and processing assets service long-lived natural gas regions that continue to experience an increase in drilling activity, including the Anadarko Basin, the Arkoma Basin, the Permian Basin and the Golden Trend area of Oklahoma. Our systems gather natural gas from oil and natural gas wells and process the raw natural gas into merchantable, or residue, gas by extracting NGLs and removing impurities. In the aggregate, our Mid-Continent systems have approximately 7,300 receipt points, consisting primarily of individual connections and, secondarily, central delivery points which are linked to multiple wells. Our gathering systems interconnect with interstate and intrastate pipelines operated by Ozark Gas Transmission, ONEOK Gas Transportation, LLC, Southern Star Central Gas Pipeline, Inc., Panhandle Eastern Pipe Line Company, LP, Northern Natural Gas Company, CenterPoint Energy, Inc., ANR Pipeline Company, El Paso Natural Gas Company and Natural Gas Pipeline Company of America.

Mid-Continent Overview

The heart of the Mid-Continent region is generally defined as running from Kansas through Oklahoma, branching into northern and western Texas, southeastern New Mexico as well as western Arkansas. The primary producing areas in the region include the Hugoton field in southwestern Kansas, the Anadarko Basin in western Oklahoma, the Permian Basin in West Texas and the Arkoma Basin in western Arkansas and eastern Oklahoma.

FERC-Regulated Transmission System

Through NOARK, we own Ozark Gas Transmission, a 565-mile FERC-regulated natural gas interstate pipeline which transports natural gas from receipt points in eastern Oklahoma, including major intrastate pipelines, and Arkansas, where the Arkoma Basin and the Fayetteville and Woodford Shales are located, to local distribution companies and industrial markets in Arkansas and Missouri and to interstate pipelines in northeastern and central Arkansas. Ozark Gas Transmission delivers natural gas primarily via six interconnects with Mississippi River Transmission Corp., Natural Gas Pipeline Company of America and Texas Eastern Transmission Corp., and receives natural gas from numerous interconnects with intrastate pipelines, including Enogex, BP s Vastar gathering system, Arkansas Oklahoma Gas Corporation, Arkansas Western Gas Company, ONEOK Gas Transmission and our own Ozark Gas Gathering system.

Mid-Continent Gathering Systems

Chaney Dell. The Chaney Dell gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. Chaney Dell s natural gas gathering operations are conducted through two gathering systems, the Westana and Chaney Dell/Chester systems. As of December 31, 2007, the combined gathering systems had approximately 3,470 miles of natural gas gathering pipelines with approximately 3,260 receipt points. The Chaney Dell system has approximately 825 active contracts with producers.

Elk City/Sweetwater. The Elk City and Sweetwater gathering system, which we consider combined due to the close geographic proximity of the processing plants they are connected to, includes approximately 450 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, including the Springer and Granite Wash plays. The Elk City and Sweetwater gathering system connects to over 470 receipt points, with a majority of the system s western end located in areas of active drilling.

Midkiff/Benedum. The Midkiff/Benedum gathering system, which we operate and have an approximate 72.8% ownership in at December 31, 2007, consists of approximately 2,500 miles of gas gathering pipeline located across four counties within the Permian Basin in Texas. 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 Midkiff/Benedum operations provide gathering and processing under approximately 150 contracts, including one with Pioneer.

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 and entered into an agreement under which Pioneer has the right to increase its ownership interest in the Midkiff/Benedum system by an additional 14.6% beginning in June 2008 and 7.4% beginning in June 2009, for an aggregate ownership interest of 49.2%. The gas sales and purchase agreement requires that all Pioneer wells in the proximity of the Midkiff/Benedum system 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.

Ozark Gas Gathering. Through NOARK, we own Ozark Gas Gathering, which owns 370 miles of intrastate natural gas gathering pipeline located in eastern Oklahoma and western Arkansas, providing access to both the well-established Arkoma Basin and the newly-exploited Fayetteville and Woodford shales. This system connects to approximately 300 receipt points and compresses and transports gas to interconnections with Ozark Gas Transmission and CenterPoint.

Velma. The Velma gathering system is located in the Golden Trend area of southern Oklahoma and the Barnett Shale area of northern Texas. As of December 31, 2007, the gathering system had approximately 1,080 miles of active pipeline with approximately 690 receipt points consisting primarily of individual connections and, secondarily, central delivery points which are linked to multiple wells. The system includes approximately 800 miles of inactive pipeline, much of which can be returned to active status as local drilling activity warrants.

Processing and Treating Plants

Chaney Dell. The Chaney Dell system processes natural gas through the Waynoka and Chester plants, both of which are active cryogenic natural gas processing facilities. The Chaney Dell system s processing operations have total capacity of approximately 230 MMcfd. The Waynoka processing plant, which began operations in December 2006 and became fully operational in July 2007, contains the most technologically advanced controls, systems and processes and demonstrates strong NGL recovery rates, including approximately 90% of ethane recovery and greater than 98% recovery of all other NGLs. As a result, we are able to process volumes far more efficiently than were previously processed at Chaney Dell s lean oil plants. Chaney Dell has a third plant, the Chaney Dell plant, which was idled in the fourth quarter of 2006 when the Waynoka plant began operations. Because of drilling activity in the Anadarko Basin, the Waynoka and Chester plants have been operating at high utilization rates. As a result, we reactivated the Chaney Dell plant in early 2008, which added 22 MMcfd of additional processing capacity. Our Chaney/Dell operations gather and process natural gas for approximately 380 producers.

Midkiff/Benedum. The Midkiff/Benedum system processes natural gas through the Midkiff and Benedum processing plants. The Midkiff plant is a 130 Mmcfd cryogenic facility in Reagan County, Texas. The facility includes three processing trains and thirteen compressors for inlet and residue recompression. The Benedum plant is a 43 Mmcfd cryogenic facility in Upton County, Texas and includes eight compressors for inlet and residue recompression. Our Midkiff/Benedum processing operations have an aggregate processing capacity of approximately 173MMcfd and gather and process natural gas for approximately 120 producers.

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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 sell natural gas to purchasers at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbon. Our Velma operations gather and process natural gas for approximately 135 producers. We have made capital expenditures at the facility to improve its efficiency and competitiveness, including installing electric-powered compressors rather than higher-cost natural gas-powered compressors used by many of our competitors. This results in higher margins, greater efficiency and lower fuel costs.

Elk City/Sweetwater. The Elk City, Sweetwater and Prentiss facilities are on the same gathering system and are referred to as our Elk City/Sweetwater operations. Our Elk City/Sweetwater operations gather and process gas for more than 160 producers. The Elk City processing plant, located in Beckham County, Oklahoma, is a cryogenic natural gas processing plant with a total capacity of approximately 130 MMcfd. We transport to, and sell natural gas to purchasers at, the tailgate of our Elk City processing plant, as well as sell NGL production to ONEOK Hydrocarbon. The Prentiss treating facility, also located in Beckham County, is an amine treating facility with a total capacity of approximately 200 MMcfd. The Sweetwater processing plant, which began operations in September 2006, is a cryogenic natural gas processing plant located in Beckham County, near the Elk City processing plant. The Sweetwater plant has a total capacity of approximately 120 MMcfd. We built the Sweetwater plant to further access natural gas production being actively developed in western Oklahoma and the Texas panhandle. Built with state-of-the-art technology, we believe that the Sweetwater plant is capable of recovering more NGLs than a lean oil processing plant. The Sweetwater plant is currently running near full capacity. As a result, we are currently in the process of expanding the processing capacity at the plant by 50% to a total processing capacity of 180 MMcfd; we expect the expansion to be completed during 2008. Through this expansion, we will extend the system s reach into the Granite Wash play in the Roberts County, Texas area, which we believe will continue to increase our natural gas processing and throughput volumes.

Natural Gas Supply

In the Mid-Continent, we have natural gas purchase, gathering and processing agreements with approximately 800 producers with terms ranging from one month to 15 years. These agreements provide for the purchase or gathering of natural gas under fixed-fee, percentage-of-proceeds or keep-whole arrangements. Most of the agreements provide for compression, treating, and/or low volume fees. Producers generally provide, in-kind, their proportionate share of compressor 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, or the gas consumed in the production of NGLs.

We have enjoyed long-term relationships with the majority of our Mid-Continent producers. For instance, on the Velma system, where we have producer relationships going back over 20 years, our top four producers, which accounted for a significant portion of our Velma volumes for the year ended December 31, 2007, have contracts with primary terms running into 2009 and 2010. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions.

Natural Gas and NGL Marketing

We typically sell natural gas to purchasers at the tailgate of our processing plants and at various delivery points on Ozark Gas Transmission and Ozark Gas Gathering. The Velma plant has access to ONEOK Gas Transportation, an intrastate pipeline, and Southern Star Central Gas Pipeline, an interstate pipeline, and we currently sell the majority of our natural gas to Conoco Phillips and Oilco Gas Co. at the average of ONEOK Gas Transportation and Southern Star Central Gas Pipeline first-of-month indices as published in *Inside FERC*. The Elk City/Sweetwater plants have access to five major interstate and intrastate downstream pipelines: Natural Gas Pipe Line of America, Panhandle Eastern Pipeline Co., CenterPoint Energy Gas Transmission Company, Northern Natural Gas Company, ANR Pipeline Company and ONEOK Gas Transmission. At our Elk City/Sweetwater plants, we sell substantially all of our natural gas to ONEOK Energy Marketing, based on first-of-month index pricing. Ozark Gas Gathering gas prices are generally based on CenterPoint Energy Gas Transmission index as published in *Inside FERC* and natural gas sales have historically been to Eagle Energy Partners. The Chaney Dell plants have access to Panhandle Eastern Pipeline Co. and Southern Star Central Gas Pipeline and we currently sell substantially all of our natural gas to Tenaska Marketing Ventures, Constellation Energy and ONEOK Energy Marketing based on first-of-month index pricing. The Midkiff/Benedum plants have access to Northern Natural Gas Company and El Paso Pipeline Company and we currently sell substantially all of our natural gas to Tenaska Marketing Ventures, Eagle Energy Partners, Odyssey Energy Services and NGTS LP based on first-of-month index pricing.

We sell our NGL production to ONEOK Hydrocarbon under four separate agreements. The Velma agreement has an initial term expiring February 1, 2011, the Elk City/Sweetwater agreement has an initial term expiring October 1, 2008 and the Chaney Dell and Midkiff/Benedum agreements have initial terms expiring September 1, 2009. NGLs under the contracts are priced at the average monthly Oil Price Information Service, or OPIS, price for the selected market.

Condensate is collected at the Velma gas plant and around the Velma gathering system and currently sold for our account to SemCrude L.P. and EnerWest Trading Company, LLC. Condensate collected at the Elk City/Sweetwater plants and around the Elk City/Sweetwater plants is currently sold to Petro Source Partners, L.P. Condensate collected at the Chaney Dell plants and around the Chaney Dell plants is currently sold to Plains Marketing. Condensate collected at the Midkiff/Benedum plants and around the Midkiff/Benedum plants is currently sold to ConocoPhillips, Oxy USA and Oasis Transportation.

Natural Gas and NGL Hedging

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 mitigate a portion of these risks through a comprehensive risk management program which employs a variety of hedging tools. The resulting combination of the underlying physical business and the financial risk management program is a conversion from a physical environment that consists of floating prices to a risk-managed environment that is characterized by fixed prices.

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) transport 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 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:

- Percentage-of-proceeds: require us to pay a percentage of revenue to the producer. This results in our being net long physical natural gas and NGLs.

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Keep-whole: require us to deliver the same quantity of natural gas at the delivery point as we received at the receipt point; any resulting NGLs produced belong to us. This results in our being long physical NGLs and short physical natural gas.

We hedge 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 a range of fixed prices.

We recognize gains and losses from the settlement of our hedges in revenue when we sell the associated physical residue natural gas or NGLs. Any gain or loss realized as a result of hedging is substantially offset in the market when we sell the physical residue natural gas or NGLs. The majority of our hedges are characterized as cash flow hedges as defined in Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. We determine gains or losses on open and closed hedging transactions as the difference between the hedge price and the physical price. This mark-to-market methodology uses daily closing NYMEX prices when applicable and an internally-generated algorithm for hedged commodities that are not traded on a market. To insure that these financial instruments will be used solely for hedging price risks and not for speculative purposes, we have established a hedging committee to review our hedges for compliance with our hedging policies and procedures. Our revolving credit facility prohibits speculative hedging and limits our overall hedge position to 80% of our equity volumes.

For additional information on our hedging activities and a summary of our outstanding hedging instruments as of December 31, 2007, please see Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

Our Appalachian Basin Operations

We own and operate approximately 1,600 miles of intrastate gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Our Appalachian operations serve approximately 6,720 wells with an average throughput of 68.7 MMcfd of natural gas for the year ended December 31, 2007. Our 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, our gathering systems transport natural gas directly to customers. Our gathering systems connect with various public utility pipelines, including Peoples Natural Gas Company, National Fuel Gas Supply, Tennessee Gas Pipeline Company, National Fuel Gas Distribution Company, Dominion East Ohio Gas Company, Columbia Gas of Ohio, Consolidated Natural Gas Co., Texas Eastern Pipeline, Columbia Gas Transmission Corp., Equitrans Pipeline Company, Gatherco Incorporated, Piedmont Natural Gas Co., Inc. and Equitable Utilities. Our systems are strategically located in the Appalachian Basin, a region characterized by long-lived, predictable natural gas reserves that are close to major eastern U.S. markets. Substantially all of the natural gas we transport in the Appalachian Basin is derived from wells operated by Atlas Energy. We are party to an omnibus agreement with Atlas Energy which is intended to maximize the use and expansion of our gathering systems and the amount of natural gas which we transport in the region.

Appalachian Basin Overview

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

Natural Gas Supply

On December 18, 2006, Atlas America, which owns a 64.0% ownership interest in Atlas Pipeline Holdings, the parent of our general partner, contributed its ownership interests in its natural gas and oil development and production subsidiaries to Atlas Energy, a then wholly-owned subsidiary of Atlas America.

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Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a then-19.4% ownership interest, in an initial public offering. Substantially all of the natural gas we transport in the Appalachian Basin is derived from wells operated by Atlas Energy.

From the inception of our operations in January 2000 through December 31, 2007, we connected 3,720 new wells to our Appalachian gathering system, 685 of which were added through acquisitions of other gathering systems. For the year ended December 31, 2007, we connected 874 wells to our gathering system. Our ability to increase the flow of natural gas through our gathering systems and to offset the natural decline of the production already connected to our gathering systems will be determined primarily by the number of wells drilled by Atlas Energy and connected to our gathering systems and by our ability to acquire additional gathering assets.

Natural Gas Revenue

Our Appalachian Basin revenue is determined primarily by the amount of natural gas flowing through our gathering systems and the price received for this natural gas. We have an agreement with Atlas Energy under which Atlas Energy pays us gathering fees generally equal to a percentage, typically 16%, of the gross weighted average sales price of the natural gas we transport subject, in most cases, to minimum prices of $0.35 or $0.40 per Mcf. For the year ended December 31, 2007, we received gathering fees averaging $1.35 per Mcf. We charge other operators fees negotiated at the time we connect their wells to our gathering systems or, in a pipeline acquisition, that were established by the entity from which we acquired the pipeline.

Because we do not buy or sell gas in connection with our Appalachian operations, we do not engage in hedging activities. Atlas Energy maintains a hedging program. Since we receive transportation fees from Atlas Energy generally based on the selling price received by Atlas Energy inclusive of the effects of financial and physical hedging, these financial and physical hedges mitigate the risk of our percentage-of-proceeds arrangements.

Our Relationship with Atlas Energy and Atlas America

We began our operations in January 2000 by acquiring the gathering systems of Atlas America. On December 18, 2006, Atlas America contributed its ownership interests in its natural gas and oil development and production subsidiaries to Atlas Energy, a then wholly-owned subsidiary of Atlas America. Atlas America currently owns 49.4% of Atlas Energy and also owns 64.0% of Atlas Pipeline Holdings, the parent of our general partner, which owns a 13.5% limited partner interest and a 2% general partner interest in us.

Atlas Energy 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 eastern Ohio, western New York and western Pennsylvania. Our gathering systems are connected to approximately 6,100 wells developed and operated by Atlas Energy in the Appalachian Basin. Through agreements between us and Atlas Energy, we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. For the year ended December 31, 2007, Atlas Energy and its affiliates raised $363.3 million from investors and drilled 1,014 wells.

Omnibus Agreement

Under the omnibus agreement, Atlas America and its affiliates agreed to add wells to our gathering systems and provide consulting services when we construct new gathering systems or extend existing systems. In December 2006, in connection with the completion of the initial public offering of, and Atlas America s contribution and sale of its natural gas and oil development and production assets to, Atlas Energy, Atlas Energy joined the omnibus agreement as an obligor (except for the provisions of the omnibus agreement imposing conditions upon our general partner s disposition of its general partner interest in us), and Atlas

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America became secondarily liable as a guarantor of Atlas Energy s performance. The omnibus agreement is a continuing obligation, having no specified term or provisions regarding termination except for a provision terminating the agreement if our general partner is removed as general partner without cause. The omnibus agreement may not be amended without the approval of the conflicts committee of the managing board of our general partner if, in the reasonable discretion of our general partner, such amendment will adversely affect our common unitholders. Our common unitholders do not have explicit rights to approve any termination or material modification of the omnibus agreement. We anticipate that the conflicts committee of the managing board of our general partner would submit to our common unitholders for their approval any proposal to terminate or amend the omnibus agreement if our general partner determines, in its reasonable discretion, that the termination or amendment would materially adversely affect our common unitholders.

Well Connections. Under the omnibus agreement, with respect to any well Atlas Energy drills and operates for itself or an affiliate that is within 2,500 feet of our gathering systems, Atlas Energy must, at its sole cost and expense, construct small diameter (two inches or less) sales or flow lines from the wellhead of any such well to a point of connection to the gathering system. Where an Atlas Energy well is located more than 2,500 feet from one of our gathering systems, but Atlas Energy has extended the flow line from the well to within 1,000 feet of the gathering system, Atlas Energy has the right to require us, at our cost and expense, to extend our gathering system to connect to that well. With respect to other Atlas Energy wells that are more than 2,500 feet from our gathering systems, we have the right, at our cost and expense, to extend our gathering system to within 2,500 feet of the well and to require Atlas Energy, at its cost and expense, to construct up to 2,500 feet of flow line to connect to the gathering system extension. If we elect not to exercise our right to extend our gathering systems, Atlas Energy may connect an Atlas Energy well to a natural gas gathering system owned by someone other than us or one of our subsidiaries or to any other delivery point; however, we will have the right to assume the cost of construction of the necessary flow lines, which will then become our property and part of our gathering systems.

Consulting Services. The omnibus agreement requires Atlas Energy to assist us in identifying existing gathering systems for possible acquisition and to provide consulting services to us in evaluating and making a bid for these systems. Atlas Energy must give us notice of identification by it or any of its affiliates of any gathering system as a potential acquisition candidate, and must provide us with information about the gathering system, its seller and the proposed sales price, as well as any other information or analyses compiled by Atlas Energy with respect to the gathering system. We must determine, within a time period specified by Atlas Energy s notice to us, which must be a reasonable time under the circumstances, whether we want to acquire the identified system and advise Atlas Energy of our intent. If we intend to acquire the system, we have an additional 60 days to complete the acquisition. If we advise Atlas Energy that we do not intend to make the acquisition, do not complete the acquisition within a reasonable time period, or advise Atlas Energy that we do not intend to acquire the system, then Atlas Energy may do so.

Gathering System Construction. The omnibus agreement requires Atlas Energy to provide us with construction management services if we determine we need to expand one or more of our gathering systems. We must reimburse Atlas Energy for its costs, including an allocable portion of employee salaries, in connection with its construction management services.

Disposition of Interest in Our General Partner. Before the completion of the Atlas Pipeline Holdings and Atlas Energy initial public offerings, Atlas America owned both our general partner and the entities which act as the general partners, operators or managers of the drilling investment partnerships sponsored by Atlas America. The omnibus agreement prohibited Atlas America from transferring its interest in our general partner unless it also transferred to the same person its interests in those subsidiaries. Atlas America was permitted, however, to transfer its interest in our general partner to a wholly- or majority-owned direct or indirect subsidiary as long as Atlas America continues to control the new entity. In connection with the Atlas Pipeline Holdings initial public offering, Atlas America transferred its interest in our general partner to Atlas Pipeline Holdings, then Atlas America s wholly-owned subsidiary. Atlas America currently owns a 64.0% interest in Atlas Pipeline Holdings.

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Natural Gas Gathering Agreements

We entered into a master natural gas gathering agreement with Atlas America and certain of its subsidiaries in connection with the completion of our initial public offering in February 2000. In December 2006, in connection with the completion of the initial public offering of, and Atlas America s contribution and sale of its natural gas and oil development and production assets to, Atlas Energy, Atlas Energy joined the master natural gas gathering agreement as an obligor. Under the master natural gas gathering agreement, we receive a fee from Atlas Energy for gathering natural gas, determined as follows:

- for natural gas from well interests allocable to Atlas America or its affiliates (excluding general or limited partnerships sponsored by them) that were connected to our gathering systems at February 2, 2000, the greater of $0.40 per Mcf or 16% of the gross sales price of the natural gas transported;

- for (i) natural gas from well interests allocable to general and limited partnerships sponsored by Atlas Energy that drill wells on or after December 1, 1999 that are connected to our gathering systems (ii) natural gas from well interests allocable to Atlas Energy or its affiliates (excluding general or limited partnerships sponsored by them) that are connected to our gathering systems after February 2, 2000, and (iii) well interests allocable to third parties in wells connected to our gathering systems at February 2, 2000, the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported; and

- for natural gas from well interests operated by Atlas Energy and drilled after December 1, 1999 that are connected to a gathering system that is not owned by us and for which we assume the cost of constructing the connection to that gathering system, an amount equal to the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported, less the gathering fee charged by the other gathering system.

Atlas Energy receives gathering fees from contracts or other arrangements with third-party owners of well interests connected to our gathering systems. However, Atlas Energy must pay gathering fees owed to us from its own resources regardless of whether it receives payment under those contracts or arrangements.

The master natural gas gathering agreement is a continuing obligation and, accordingly, has no specified term or provisions regarding termination. However, if our general partner is removed as our general partner without cause, then no gathering fees will be due under the agreement with respect to new wells drilled by Atlas Energy.

The master natural gas gathering agreement may not be amended without the approval of the conflicts committee of the managing board of our general partner if, in the reasonable discretion of our general partner, such amendment will adversely affect our common unitholders. Common unitholders do not have explicit rights to approve any termination or material modification of the master natural gas gathering agreement. We anticipate that the conflicts committee of the managing board of our general partner would submit to our common unitholders for their approval any proposal to terminate or amend the master natural gas gathering agreement if our general partner determines, in its reasonable discretion, that the termination or amendment would materially adversely affect our common unitholders.

In addition to the master natural gas gathering agreement, we have three other gas gathering agreements with subsidiaries of Atlas Energy. Under two of these agreements, relating to certain wells located in southeastern Ohio and in Fayette County, Pennsylvania, we receive a fee of $0.80 per Mcf. Under the third agreement, which covers wells owned by third parties unrelated to Atlas Energy or the investment partnerships it sponsors, we receive fees that range between $0.20 to $0.29 per Mcf or between 10% to 16% of the weighted average sales price for the natural gas we transport.

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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/servicing operations. These operations include plants and gathering systems operated by Duke Energy Field Services, ONEOK Field Services, Enogex, Inc., Enbridge, Inc., Hiland Partners, Mustang Fuel Corporation, DCP Midstream, J.L. Davis and Targa Resources. 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

- 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 and, possibly, could lose wells already connected to our systems.

Being a regulated entity, Ozark Gas Transmission faces somewhat more indirect competition that is more regional or even national in character. CenterPoint Energy, Inc. s interstate system is the nearest direct competitor.

Appalachian Basin. Our Appalachian Basin operations do not encounter direct competition in their service areas since Atlas Energy controls the majority of the drillable acreage in each area. However, because our Appalachian Basin operations principally serve wells drilled by Atlas Energy, we are affected by competitive factors affecting Atlas Energy s ability to obtain properties and drill wells, which affects our ability to expand our gathering systems and to maintain or increase the volume of natural gas we transport and, thus, our transportation revenues. Atlas Energy also may encounter competition in obtaining drilling services from third-party providers. Any competition it encounters could delay Atlas Energy in drilling wells for its sponsored partnerships, and thus delay the connection of wells to our gathering systems. These delays would reduce the volume of natural gas we otherwise would have transported, thus reducing our potential transportation revenues.

As our omnibus agreement with Atlas Energy generally requires it to connect wells it operates to our system, we do not expect any direct competition in connecting wells drilled and operated by Atlas Energy in the future. In addition, we occasionally connect wells operated by third parties. For the year ended December 31, 2007, we connected 38 third-party wells.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. FERC regulates our interstate natural gas pipeline interests. Ozark Gas Transmission transports natural gas in interstate commerce. As a result, Ozark Gas Transmission qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- rate structures;

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- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters. Natural gas companies may only charge rates that have been determined to be just and reasonable in proceedings before FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities. Any successful complaint or protest against Ozark Gas Transmission s FERC-approved rates could have an adverse impact on our revenues associated with providing transmission services.

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own a number of intrastate natural gas pipelines in New York, Pennsylvania, Ohio, Arkansas, Kansas, Oklahoma and Texas that we believe would 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 the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC and the courts.

In Ohio, a producer or gatherer of natural gas may file an application seeking exemption from regulation as a public utility, except for the continuing jurisdiction of the Public Utilities Commission of Ohio to inspect our gathering systems for public safety purposes. Our operating subsidiary has been granted an exemption by the Public Utilities Commission of Ohio for our Ohio facilities. The New York Public Service Commission imposes traditional public utility regulation on the transportation of natural gas by companies subject to its regulation. This regulation includes rates, services and siting authority for the construction of certain facilities. Our gas gathering operations currently are not subject to regulation by the New York Public Service Commission. Our operations in Pennsylvania currently are not subject to the Pennsylvania Public Utility Commission s regulatory authority since they do not provide service to the public generally and, accordingly, do not constitute the operation of a public utility. Similarly, our operations in Arkansas are not subject to rate oversight by the Arkansas Public Service Commission, but may, in certain circumstances, be

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subject to safety and environmental regulation by such commission or the Arkansas Oil and Gas Commission. In the event the Arkansas, Ohio, New York or Pennsylvania authorities seek to regulate our operations, we believe that our operating costs could increase and our transportation fees could be adversely affected, thereby reducing our net revenues and ability to make distributions to our general partner and common unitholders.

Nonetheless, 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 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. 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 transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the Texas Railroad Commission has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of one customer over another. 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 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 or 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. A portion of our revenues is tied to the price of natural gas. The wholesale price of natural gas is not currently subject to federal regulation and, for the most part, is not subject to state regulation. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other companies with whom we compete.

Energy Policy Act of 2005. The Energy Policy Act contains numerous provisions relevant to the natural gas industry and to interstate pipelines in particular. Overall, the legislation attempts to increase supply sources by engaging in 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 primary provisions of interest to our interstate pipelines focus on two areas: (1) infrastructure development; and (2) market transparency and

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enhanced enforcement. Regarding infrastructure development, the Energy Policy Act includes provisions to clarify that FERC has exclusive jurisdiction over the siting of liquefied natural gas terminals; provides for market-based rates for new 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; creates a consolidated record for all federal decisions relating to necessary authorizations and permits; and provides for expedited judicial review of any agency action and review by only the D.C. Circuit Court of Appeals of any alleged failure of a federal agency to act 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 rules, the Natural Gas Act is amended to prohibit market manipulation and add provisions for 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 are also amended to increase monetary criminal penalties to $1,000,000 from current law at $5,000 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.

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, 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 and 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 substances or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances 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.

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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 less stringent 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.

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 as well as natural gas is excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations we will generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the 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. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. 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 remedial closure 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 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 strictly 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.

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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 an appropriately issued permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation (DOT), under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers the pipeline transportation of natural gas and other gases, and the transportation and storage of liquefied natural gas and requires any entity that owns or operates pipeline facilities to comply with the regulations under the NGPSA, 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 NGPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA could result in increased costs.

The DOT, through the Office of Pipeline Safety, recently finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. The Texas Railroad Commission, the Oklahoma Corporation Commission and other state agencies have adopted similar regulations applicable to intrastate gathering and transmission lines. Compliance with these existing rules has not had a material adverse effect on our operations but there is no assurance that this trend will continue in the future.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, as amended, referred to as 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.

Properties

As of December 31, 2007, our principal facilities in Appalachia include approximately 1,600 miles of 2 to 12 inch diameter pipeline. Our principal facilities in the Mid-Continent area consist of seven natural gas processing plants, one treating facility, and approximately 8,670 miles of active and inactive 2 to 42 inch diameter pipeline. Substantially all of our gathering systems and our transmission pipeline are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

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Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not interfered, and our general partner does 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 right-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 right-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, for 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. In addition, 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 Atlas America and its affiliates manage our gathering systems and operate our business. Atlas America employed approximately 373 people at December 31, 2007 who provided direct support to our operations.

Affiliates of our general partner will conduct business and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition between us, our general partner and affiliates of our general partner for the time and effort of the officers and employees who provide services to our general partner. The officers of our general partner who provide services to us are not required to work full time on our affairs. These officers may devote significant 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 significant conflicts between us and affiliates of our general partner regarding the availability of these officers to manage us.

Available Information

We make our periodic reports under the Securities Exchange Act of 1934, including our annual report on Form 10-K, our quarterly reports on Form 10-Q and our current reports on Form 8-K, available through our website at www.atlaspipelinepartners.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., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The Chief Executive Officer of our general partner provided such certification to the NYSE in 2007 without qualification. In addition, the certifications of the Chief Executive Officer and Chief Financial Officer of our general partner required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this report.

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 at our current or any other level of distribution. 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 and price of natural gas and NGLs;
- the volume of natural gas we transport;
- expiration of significant contracts;
- continued development of wells for connection to our gathering systems;
- the availability of local, intrastate and interstate transportation systems;
- 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;

government regulation and taxation; 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;
- our debt service requirements and requirements to pay dividends on our outstanding preferred units, and restrictions on distributions contained in our current or future debt agreements; and
- the amount of cash reserves established by our general partner for the conduct of our business.

We can t 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 can t 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.

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

Our debt levels and restrictions in our credit facility could limit our ability to make distributions to our unitholders.

We have a significant amount of debt. We will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing 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 distributions, 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 effect any of these remedies on satisfactory terms, or at all.

Our profitability is affected by the volatility of prices for natural gas and NGL 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. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our gross margin for the twelve-month period ended December 31, 2008 of approximately $3.7 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations and thus the volume of gas we gather and process. Historically, the price of both natural gas and NGLs has been subject to significant volatility in response to relatively minor changes in the supply and demand for natural gas and NGL 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. We expect this volatility to continue. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in Our hedging strategies may fail to protect us and could reduce our gross margin and cash flow.

The amount of natural gas we transport 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 transport reducing 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. 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, geological considerations, governmental regulation and the availability and cost of capital. Because our operating costs are fixed to a significant degree, a reduction in the natural gas volumes we transport or process would result in a reduction in our gross margin and cash flows.

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

If one or more of the pipelines 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, the amount of NGLs we 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 success of our Appalachian operations depends upon Atlas Energy s ability to drill and complete commercial producing wells.

Substantially all of the wells we connect to our gathering systems in our Appalachian service area are drilled and operated by Atlas Energy for drilling investment partnerships sponsored by it. As a result, our Appalachian operations depend principally upon the success of Atlas Energy in sponsoring drilling investment partnerships and completing wells for these partnerships. Atlas Energy operates in a highly competitive environment for acquiring undeveloped leasehold acreage and attracting capital. Atlas Energy may not be able to compete successfully in the future in acquiring undeveloped leasehold acreage or in raising additional capital through its drilling investment partnerships. Furthermore, Atlas Energy is not required to connect wells for which it is not the operator to our gathering systems. If Atlas Energy cannot or does not continue to sponsor drilling investment partnerships, if the amount of money raised by those partnerships decreases, or if the number of wells actually drilled and completed as commercially producing wells decreases, the amount of natural gas transported by our Appalachian gathering systems would substantially decrease and could, upon exhaustion of the wells currently connected to our gathering systems, cause us to abandon one or more of our Appalachian gathering systems, thereby materially reducing our gross margin and cash flows.

The failure of Atlas Energy to perform its obligations under our natural gas gathering agreements with it may adversely affect our business.

Substantially all of our Appalachian operating system revenues currently consist of the fees we receive under the master natural gas gathering agreement and other transportation agreements we have with Atlas Energy and its affiliates. We expect to derive a material portion of our gross margin from the services we provide under our contracts with Atlas Energy for the foreseeable future. Any factor or event adversely affecting Atlas Energy s business or its ability to perform under its contracts with us or any default or nonperformance by Atlas Energy of its contractual obligations to us, could reduce our gross margin and cash flows.

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

Unlike our Appalachian operations, none of the drillers or operators in our Mid-Continent service area is an affiliate of ours. Moreover, our agreements with most of the drillers and operators with which our Mid-Continent operations do business do not require them to dedicate significant amounts of undeveloped acreage to our systems. As a result, 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 will, as described in The amount of natural gas we transport will decline over time unless we are able to attract new wells to connect to our gathering systems, above, 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 2007, Chesapeake Energy Corporation, Pioneer, Conoco Phillips, Sanguine Gas Exploration, LLC, St. Mary Land and Exploration Company, XTO Energy Inc., Henry Petroleum, L.P. and Senex Pipeline Company supplied our Mid-Continent systems with a majority of their 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 service areas.

Our Mid-Continent operations may face competition for well connections. Duke Energy Field Services, LLC, ONEOK, Inc., Carrera Gas Company, Cimmarron Transportation, LLC and Enogex, Inc. operate competing gathering systems and processing plants in our Velma service area. In our Elk City and Sweetwater service area, ONEOK Field Services, Eagle Rock Midstream Resources, L.P., Enbridge Energy Partners, L.P., CenterPoint Energy, Inc. and Enogex Inc. operate competing gathering systems and processing plants. CenterPoint Energy, Inc. s interstate system is the nearest direct competitor to our Ozark Gas Transmission system. CenterPoint and Hiland Partners operate competing gathering systems in Ozark Gas Gathering s service area. Hiland Partners, DCP Midstream, Mustang Fuel Corporation and ONEOK Partners operate competing gathering systems and processing plants in our Chaney Dell service area. DCP Midstream, J.L. Davis, and Targa Resources 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 areas, we may not be able to compete successfully with them in securing new well connections or retaining current well connections. If we do not compete successfully, the amount of natural gas we transport, process and treat will decrease, reducing our gross margin and cash flows.

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The amount of natural gas we transport, treat or process may be reduced if the public utility 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 sales lines from wells connected to our systems and the public utility 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 transport, and we cannot arrange for delivery to other pipelines, local distribution companies or end users, the amount of natural gas we transport may be reduced. Since our revenues depend upon the volumes of natural gas we transport, this could result in a material reduction in 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;
- 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 increase distributions.

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

We acquired the Chaney Dell and the Midkiff/Benedum systems in July 2007 and are currently in the process of integrating their operations with ours. We also have an active, on-going program to identify other potential acquisitions. The integration of previously independent operations with ours can be a complex, costly and time-consuming process. The difficulties of combining these systems, as well as any operations we may acquire in the future, with us 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 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.

We acquired the Chaney Dell and Midkiff/Benedum systems with the expectation that combining them with our existing operations will result in benefits, including, among other things, benefits from organic growth and synergies, increased scale and presence in the Mid-Continent area, expansion of relationships with top producers and increased geographic diversification. There can be no assurance that we will realize any of these benefits or that the acquisition will not result in the deterioration or loss of our business. In addition, our investment in the interconnection of our Elk City/Sweetwater and Chaney Dell systems and the additional overhead costs we incur to grow our NGL 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.

The acquisitions of the Chaney Dell and the Midkiff/Benedum systems have substantially changed our business, making it difficult to evaluate our business based upon our historical financial information.

The acquisitions of the Chaney Dell and the Midkiff/Benedum systems have significantly increased our size and substantially redefined our business plan, expanded our geographic market and resulted in large changes to our revenues and expenses. As a result of these acquisitions, and our continued plan to acquire and integrate additional companies that we believe present attractive opportunities, our financial results for any period or changes in our results across periods may continue to dramatically change. Our historical financial results, therefore, should not be relied upon to accurately predict our future operating results, thereby making the evaluation of our business more difficult.

Due to our lack of asset diversification, negative developments in our operations would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our transportation, gathering and processing operations, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. 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.

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, such as the Sweetwater plant. The construction of additions or modifications to our existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. Any projects we undertake may not be completed on schedule at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a gathering

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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 recently completed construction of our Sweetwater natural gas processing plant, from which we expect to generate additional incremental cash flow. We also continue to expand the natural gas gathering system surrounding Sweetwater in order to maximize its plant throughput. In addition to the risks discussed above, expected incremental revenue from the Sweetwater natural gas processing plant could be reduced or delayed due to the following reasons:

- difficulties in obtaining equity or debt financing 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.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then we may be unable to fully execute our growth strategy and 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.

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

Currently our gathering and processing of natural gas is exempt from regulation under the Natural Gas Act of 1938. However, the implementation of new laws or policies, or interpretations of existing laws, could subject us to regulation by FERC under the Natural Gas Act, the Natural Gas Policy Act, or other laws enacted after the date of this Form 10-K. Any such regulation would increase our costs, decrease our gross margin and cash flows, or both.

Nonetheless, FERC regulation will still affect our business and the market for our products. FERC s policies and practices affect a range of our natural gas pipeline activities, including, for example, its policies on open access transportation, ratemaking, capacity release, environmental protection and market center

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promotion, which indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Since federal law generally leaves any economic regulation of natural gas gathering to the states, state and local regulations may also affect our business. Matters subject to such regulation include access, rates, terms of service and safety. For example, our gathering lines are subject to ratable take, common purchaser, and similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Texas and Oklahoma 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 or Oklahoma 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 transport natural gas.

Increased regulatory requirements relating to the integrity of the Ozark Gas Transmission pipeline and our other assets could require us to spend additional money to comply with these requirements. In particular, Ozark Gas Transmission is subject to extensive laws and regulations related to pipeline integrity. Federal legislation signed into law in December 2002 includes guidelines for the U.S. Department of Transportation and pipeline companies in the areas of testing, education, training and communication. Compliance with existing and recently enacted regulations requires significant expenditures. Additional laws and regulations that may be enacted in the future, such as U.S. Department of Transportation implementation of additional hydrostatic testing requirements, could significantly increase the amount of these expenditures.

Ozark Gas Transmission is subject to FERC rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating the pipeline.

Rate-making policies by FERC could affect Ozark Gas Transmission s ability to establish rates, or to charge rates that would cover future increases in its costs, or even to continue to collect rates that cover current costs. Natural gas companies may only charge rates that have been determined to be just and reasonable by FERC. The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas capacity and transportation facilities. Any successful complaint or protest against Ozark Gas Transmission s rates could reduce our revenues associated with providing transmission services. We cannot assure you that we will be able to recover all of Ozark Gas Transmission s costs through existing or future rates.

Ozark Gas Transmission is subject to regulation by FERC in addition to FERC rules and regulations related to the rates it can charge for its services.

FERC s regulatory authority also extends to:

- operating terms and conditions of service;
- the types of services Ozark Gas Transmission s may offer to its customers;

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construction of new facilities;

acquisition, extension or abandonment of services or facilities;

accounts and records; and

relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

FERC action in any of these areas or modifications of its current regulations can impair Ozark Gas Transmission s ability to compete for business, the costs it incurs in its operations, the construction of new facilities or its ability to recover the full cost of operating its pipeline. For example, revisions to interstate gas quality standards by FERC could create two distinct markets for natural gas an interstate market subject to minimum quality standards and an intrastate market with different minimum quality standards. Such a bifurcation of markets could make it difficult for our pipelines to compete in both markets or to attract certain gas supplies away from the intrastate market. The time FERC takes to approve the construction of new facilities could raise the costs of our projects to the point where they are no longer economic.

FERC has authority over the terms and conditions of interstate pipeline services. Under FERC s open access requirements, service generally must be undertaken pursuant to the terms and conditions of the pipeline s open access tariff. Contracts for such services that deviate in a material manner from a pipeline s tariff must be filed for approval by FERC or, alternatively, the pipeline must amend its generally available tariff to include the deviating terms, thereby offering it to all shippers. If FERC audits a pipeline s contracts and finds deviations that appear to be unduly discriminatory, FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should Ozark Gas Transmission s fail to comply with all applicable FERC administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act, FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1,000,000 per day for each violation.

Finally, we cannot give any assurance regarding the likely future regulations under which we will operate Ozark Gas Transmission or the effect such regulation could have on our business, financial condition, and results of operations.

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.

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We do not believe that the cost of implementing integrity management program testing along certain segments of our pipeline will 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 determined to be necessary as a result of the testing program, which 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 can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of 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, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

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 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 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.

We may issue additional units, which may increase the risk of not having sufficient available cash to maintain or increase our per unit distribution level.

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 maintain or increase our per unit distribution level. 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.

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

We pursue various hedging strategies to seek to reduce our exposure to losses from adverse changes in the prices for natural gas, condensate and NGLs. Our hedging activities will vary in scope based upon the level and volatility of natural gas, condensate and NGL prices and other changing market conditions. Our hedging activity may fail to protect or could harm us because, among other things:

- hedging can be expensive, particularly during periods of volatile prices;
- available hedges may not correspond directly with the risks against which we seek protection;
- the duration of the hedge may not match the duration of the risk against which we seek protection; and
- the party owing money in the hedging transaction may default on its obligation to pay.

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

Our operations are subject to federal and state environmental laws under which owners of natural gas pipelines can be liable for clean-up costs and fines in connection with any pollution caused by their pipelines. We may also be held liable for clean-up costs resulting from pollution which occurred before our acquisition of the gathering systems. In addition, we are subject to federal and state safety laws that dictate the type of pipeline, quality of pipe protection, depth, 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.

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We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our 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 action necessitated by those regulations.

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

Our operations are subject to all operating hazards and risks incidental to transporting 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, transmission and distribution 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.

The IRS could treat us as a corporation for tax purposes, which could substantially reduce our cash flow.

If we were treated as a corporation for U.S. federal income tax purposes for any taxable year for which the statute of limitations remains open or any future year, we would pay federal income tax on our taxable income for such year at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Because a tax would be imposed on us as a corporation, our cash flow would be substantially reduced.

Risks Related to Our Ownership Structure

Atlas America and its affiliates, including Atlas Energy, have conflicts of interest and limited fiduciary responsibilities, which may permit them to favor their own interests to the detriment of our unitholders.

Atlas America and its affiliates own and control our general partner, which also owns a 13.5% limited partner interest in us. We do not have any employees and rely solely on employees of Atlas America and its affiliates who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of Atlas America also own interests in us. Conflicts of interest may arise between Atlas America, our general partner and their affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over our interests and the interests of our unitholders. These conflicts include, among others, the following situations:

Employees of Atlas America who provide services to us also devote significant time to the businesses of Atlas America in which we have no economic interest. If these separate activities are significantly 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.

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Neither our partnership agreement nor any other agreement requires Atlas America to pursue a future business strategy that favors us or, apart from our agreements with Atlas America relating to our Appalachian region operations, use our assets for transportation or processing services we provide. Atlas America s directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of Atlas America.

Our general partner is allowed to take into account the interests of parties other than us, such as Atlas America, 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, including our agreements with Atlas Energy.

Conflicts of interest with Atlas America and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our gross margin and cash flows.

Cost reimbursements due our general partner may be substantial and will reduce the cash available for distributions to our unitholders.

We reimburse Atlas America, our general partner and their affiliates, including officers and directors of Atlas America, for all expenses they incur on our behalf. Our general partner has sole discretion to determine the amount of these expenses. In addition, Atlas America and its affiliates provide us with services for which we are charged reasonable fees as determined by Atlas America in its sole discretion. The reimbursement of expenses or payment of fees could adversely affect our ability to make distributions to our unitholders.

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 but, pursuant to the purchase option agreement, has the right to acquire up to an additional 22% interest.

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ITEM 1B. UNRESOLVED STAFF COMMENTS
Not Applicable.

ITEM 2. PROPERTIES
A description of our properties is contained within Item 1, Business .

ITEM 3. LEGAL PROCEEDINGS
We are not subject to any pending material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS
No matters were submitted to a vote of the common unitholders during the year ended December 31, 2007.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED UNITHOLDER MATTERS
Our common units are listed on the New York Stock Exchange under the symbol APL . At the close of business on February 27, 2008, the closing price for the common units was $44.36 and there were 138 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, 2007 and 2006:

	High	Low	Distributions Declared
2007			
Fourth Quarter	$ 49.58	$ 41.92	$ 0.93
Third Quarter	$ 55.50	$ 42.62	$ 0.91
Second Quarter	$ 56.88	$ 47.81	$ 0.87
First Quarter	$ 51.70	$ 46.64	$ 0.86
2006			
Fourth Quarter	$ 49.56	$ 43.10	$ 0.86
Third Quarter	$ 44.60	$ 40.15	$ 0.85
Second Quarter	$ 42.90	$ 39.55	$ 0.85
First Quarter	$ 43.00	$ 39.80	$ 0.84

For a description of our recent sale of unregistered securities, see our current report on Form 8-K filed July 30, 2007.

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.

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

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

Minimum Distributions Per Unit Per Quarter	Percent of Available Cash in Excess of Minimum Allocated to the General Partner
$0.42	15%
$0.52	25%
$0.60	50%

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. During July 2007, our general partner, the holder of all of our incentive distribution rights, had agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter, in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems. The general partner s incentive distributions declared for the year ended December 31, 2007, after the allocation of $9.9 million of its incentive distribution rights to us, were $15.9 million.

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 Stockholder Matters .

ITEM 6. SELECTED FINANCIAL DATA

The following table should be read together with our consolidated financial statements and notes thereto included within Item 8, Financial Statements and Supplementary Data and Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations of this report. We have derived the selected financial data set forth in the table for each of the years ended December 31, 2007, 2006 and 2005 and at December 31, 2007 and 2006 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 as of December 31, 2005, 2004 and 2003 and for the years ended December 31, 2004 and 2003 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

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	Years Ended December 31,				
	2007[1]	**2006[2]**	**2005[3]**	**2004[4]**	**2003**
	(in thousands, except per unit and operating data)				
Statement of operations data:					
Revenue:					
Natural gas and liquids	$ 761,118	$ 391,356	$ 338,672	$ 72,364	$
Transportation, compression and other fees	81,785	60,924	30,309	18,800	15,651
Other income (loss)	(174,103)	12,412	2,519	127	98
Total revenue and other income (loss)	668,800	464,692	371,500	91,291	15,749
Costs and expenses:					
Natural gas and liquids	587,524	334,299	288,180	58,707	
Plant operating	34,667	15,722	10,557	2,032	
Transportation and compression	13,484	10,753	4,053	2,260	2,421
General and administrative	60,986	22,569	13,608	4,643	1,661
Depreciation and amortization	50,982	22,994	13,954	4,471	1,770
Loss (gain) on arbitration settlement, net			138	(1,457)	
Interest	61,526	24,572	14,175	2,301	258
Minority interests[5]	3,940	118	1,083		
Total costs and expenses	813,109	431,027	345,748	72,957	6,110
Net income (loss)	(144,309)	33,665	25,752	18,334	9,639
Preferred unit imputed dividend cost	(2,494)	(1,898)			
Preferred unit dividend effect	(3,756)				
Premium on preferred unit redemption				(400)	
Net income (loss) attributable to common limited partners and the general partner	$ (150,559)	$ 31,767	$ 25,752	$ 17,934	$ 9,639
Net income (loss) attributable to common limited partners per unit:					
Basic	$ (6.75)	$ 1.29	$ 1.86	$ 2.53	$ 2.17
Diluted[6]	$ (6.75)	$ 1.27	$ 1.84	$ 2.53	$ 2.17
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 1,748,661	$ 607,097	$ 445,066	$ 175,259	$ 29,628
Total assets	2,877,614	786,884	742,726	216,785	49,512
Total debt, including current portion	1,229,426	324,083	298,625	54,452	
Total partners capital	1,273,960	379,134	329,510	136,704	44,245
Cash flow data:					
Net cash provided by operating activities	$ 99,769	$ 45,029	$ 49,520	$ 24,301	$ 13,702
Net cash used in investing activities	(2,024,643)	(104,499)	(409,607)	(150,905)	(9,154)
Net cash provided by financing activities	1,935,059	27,028	376,110	129,740	8,671
Other financial data:					
Gross margin [7]	$ 265,802	$ 119,071	$ 79,711	$ 32,457	$ 15,651
EBITDA [8]	(21,378)	82,321	52,791	25,106	11,667
Adjusted EBITDA [8]	185,780	86,320	56,509	25,596	11,667
Maintenance capital expenditures	$ 9,115	$ 4,649	$ 1,922	$ 1,516	$ 3,109
Expansion capital expenditures	143,775	79,182	50,576	8,527	4,526
Total capital expenditures	$ 152,890	$ 83,831	$ 52,498	$ 10,043	$ 7,635
Operating data[9]:					
Appalachia:					

Average throughput volumes (mcfd)	68,715	61,892	55,204	53,343	52,472
Average transportation rate per mcf	$ 1.35	$ 1.34	$ 1.21	$ 0.96	$ 0.82
Mid-Continent:					
Velma system:					
Gathered gas volume (mcfd)	62,497	60,682	67,075	56,441	
Processed gas volume (mcfd)	60,549	58,132	62,538	55,202	
Residue gas volume (mcfd)	47,234	45,466	50,880	42,659	
NGL volume (bpd)	6,451	6,423	6,643	5,799	
Condensate volume (bpd)	225	193	256	185	
Elk City/Sweetwater system:					
Gathered gas volume (mcfd)	298,200	277,063	250,717		
Processed gas volume (mcfd)	225,783	154,047	119,324		
Residue gas volume (mcfd)	206,721	140,969	109,553		
NGL volume (bpd)	9,409	6,400	5,303		
Condensate volume (bpd)	212	140	127		
Chaney Dell system(10):					
Gathered gas volume (mcfd)	259,270				
Processed gas volume (mcfd)	253,523				
Residue gas volume (mcfd)	221,066				
NGL volume (bpd)	12,900				
Condensate volume (bpd)	572				
Midkiff/Benedum system(10):					
Gathered gas volume (mcfd)	147,240				
Processed gas volume (mcfd)	103,628				
Residue gas volume (mcfd)	94,281				
NGL volume (bpd)	20,618				
Condensate volume (bpd)	1,346				
NOARK system:					
Average Ozark Gas Transmission throughput volume (mcfd)	326,651	249,581	255,777		

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(1) 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.

(2) Includes our acquisition of the remaining 25% ownership interest in NOARK on May 2, 2006, representing approximately eight months of an additional 25% ownership interest in NOARK s operations for the year ended December 31, 2006. Operating data for the NOARK system represents 100% of its operating activity.

(3) Includes our acquisition of Elk City on April 14, 2005, representing approximately eight and one-half months operations, and a 75% ownership interest in NOARK on October 31, 2005, representing approximately two months operations, for the year ended December 31, 2005. Operating data for the NOARK system represents 100% of its operating activity.

(4) Includes our acquisition of Spectrum on July 16, 2004, representing approximately five and one-half months operations for the year ended December 31, 2004.

(5) For the years ended December 31, 2006 and 2005, this represents Southwestern s 25% minority interest in the net income of NOARK. We acquired Southwestern s 25% ownership interest on May 2, 2006. For the year ended December 31, 2007, this represents Anadarko s 5% minority interest in the operating results of the Chaney Dell and Midkiff Benedum systems, which we acquired on July 27, 2007.

(6) For the year ended December 31, 2007, approximately 524,000 phantom units were excluded from the computation of diluted net income (loss) attributable to common limited partner units because the inclusion of such units would have been anti-dilutive. For the years ended December 31, 2007 and 2006, potential common limited partner units issuable upon conversion of our 40,000 $1,000 par value cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

(7) We define gross margin as revenue less purchased product costs. Purchased product costs include the cost of natural gas and NGLs that we purchase from third parties. 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 net income (loss) to gross margin (in thousands):

	Years Ended December 31,				
	2007(1)	**2006(2)**	**2005(3)**	**2004(4)**	**2003**
Net income (loss)	$ (144,309)	$ 33,665	$ 25,752	$ 18,334	$ 9,639
Adjustments:					
Effect of prior period items(11)		1,090	(1,090)		
Other (income) loss	174,103	(12,412)	(2,519)	(127)	(98)
Plant operating	34,667	15,722	10,557	2,032	
Transportation and compression	13,484	10,753	4,053	2,260	2,421
General and administrative	60,986	22,569	13,608	4,643	1,661
Depreciation and amortization	50,982	22,994	13,954	4,471	1,770
Loss (gain) on arbitration settlement, net			138	(1,457)	
Interest	61,526	24,572	14,175	2,301	258
Minority interests(5)	3,940	118	1,083		
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition(12)	10,423				
Gross margin	$ 265,802	$ 119,071	$ 79,711	$ 32,457	$ 15,651

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(8) EBITDA represents net income (loss) before net interest expense, income taxes, and depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees. 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 EBITDA calculation below is different from the EBITDA calculation 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):

	Years Ended December 31,				
	2007[1]	2006[2]	2005[3]	2004[4]	2003
Net income (loss)	$ (144,309)	$ 33,665	$ 25,752	$ 18,334	$ 9,639
Adjustments:					
Effect of prior period items[11]		1,090	(1,090)		
Interest expense	61,526	24,572	14,175	2,301	258
Depreciation and amortization	50,982	22,994	13,954	4,471	1,770
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition[12]	10,423				
EBITDA	$ (21,378)	$ 82,321	$ 52,791	$ 25,106	$ 11,667
Adjustments:					
Non-cash loss (gain) on derivative movements	169,424	(2,316)	(954)	(210)	
Non-cash compensation expense	36,320	6,315	4,672	700	
Other non-cash items[13]	1,414				
Adjusted EBITDA	$ 185,780	$ 86,320	$ 56,509	$ 25,596	$ 11,667

(9) Mcf represents thousand cubic feet; mcfd represents thousand cubic feet per day; bpd represents barrels per day.

(10) 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.

(11) During June 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 the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively.

(12) 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.

(13) Includes the cash proceeds received from the sale of our Enville plant and the non-cash loss recognized within our statements of 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 notes thereto appearing elsewhere in this report.

General

We are a publicly-traded Delaware limited partnership whose common units are listed on the New York Stock Exchange under the symbol APL . Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko, Arkoma, Golden Trend and Permian Basins in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treatment services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas and southeastern Missouri. Our business is conducted in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

Through our Mid-Continent operations, we own and operate:

- a FERC-regulated, 565-mile interstate pipeline system that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 400 MMcfd;

- seven natural gas processing plants with aggregate capacity of approximately 750 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and

- 7,870 miles of active natural gas gathering systems located in Oklahoma, Arkansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or transmission lines.

Through our Appalachian operations, we own and operate 1,600 miles of natural gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Through an omnibus agreement and other agreements between us and Atlas America, Inc., (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

Significant Acquisitions

From the date of our initial public offering in January 2000 through December 2007, we have completed seven acquisitions at an aggregate cost of approximately $2.4 billion, including, most recently:

- On July 27, 2007, we acquired control of Anadarko s 100% interest in the Chaney Dell natural gas gathering system 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 (the Anadarko Assets). The Chaney Dell system includes 3,470 miles of gathering

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pipeline and three processing plants, while the Midkiff/Benedum system includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. In connection with this acquisition, we reached an agreement with Pioneer Natural Resources Company, which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer will have an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008, and up to an additional 7.4% interest beginning on June 15, 2009. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercised the purchase options. We funded the purchase price, in part, from our private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. Our general partner, which holds all of our incentive distribution rights, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter (see Partnership Distributions). We funded the remaining purchase price from an $830.0 million senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013 (see Term Loan and Credit Facility).

In May 2006, we acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Company (Southwestern) for a net purchase price of $65.5 million, consisting of $69.0 million in cash to the seller, (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in working capital at the date of acquisition of $3.5 million. In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owned the initial 75% ownership interest in NOARK, for $163.0 million, plus $16.8 million for working capital adjustments and related transaction costs. NOARK s principal assets include the Ozark Gas Transmission system, a 565-mile interstate natural gas pipeline, and Ozark Gas Gathering, a 365-mile natural gas gathering system.

In April 2005, we acquired all of the outstanding equity interests of Elk City for $196.0 million, including related transaction costs. Elk City s principal assets currently include approximately 450 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, a natural gas processing facility in Elk City, Oklahoma, with a total capacity of approximately 130 MMcfd and a gas treatment facility in Prentiss, Oklahoma, with a total capacity of approximately 200 MMcfd.

Contractual Revenue Arrangements

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

- the volumes of natural gas we gather, transport 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 and NGLs; and

- the transportation and processing fees we receive which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has exceeded this minimum generally. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, 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, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas received by our Elk City/Sweetwater and Chaney Dell systems, which have keep-whole contracts, is generally low in liquids content and meets 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. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

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 for natural gas transportation and 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, flexibility, 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 and NGLs. 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. The number of active oil and gas rigs has increased in recent years, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during the current and future periods. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity 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. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our gross margin for the twelve-month period ending December 31, 2008 of approximately $3.7 million.

Results of Operations

The following table illustrates selected volumetric information related to our reportable segments for the periods indicated:

	Years Ended December 31,		
	2007	2006	2005
Operating data(1):			
Appalachia:			
Average throughput volumes (mcfd)	68,715	61,892	55,204
Average transportation rate per mcf	$ 1.35	$ 1.34	$ 1.21
Mid-Continent:			
Velma system:			
Gathered gas volume (mcfd)	62,497	60,682	67,075
Processed gas volume (mcfd)	60,549	58,132	62,538
Residue gas volume (mcfd)	47,234	45,466	50,880
NGL volume (bpd)	6,451	6,423	6,643
Condensate volume (bpd)	225	193	256
Elk City/Sweetwater system:			
Gathered gas volume (mcfd)	298,200	277,063	250,717
Processed gas volume (mcfd)	225,783	154,047	119,324
Residue gas volume (mcfd)	206,721	140,969	109,553
NGL volume (bpd)	9,409	6,400	5,303
Condensate volume (bpd)	212	140	127
Chaney Dell system(2):			
Gathered gas volume (mcfd)	259,270		
Processed gas volume (mcfd)	253,523		
Residue gas volume (mcfd)	221,066		
NGL volume (bpd)	12,900		
Condensate volume (bpd)	572		
Midkiff/Benedum system(2):			
Gathered gas volume (mcfd)	147,240		
Processed gas volume (mcfd)	103,628		
Residue gas volume (mcfd)	94,281		
NGL volume (bpd)	20,618		

Condensate volume (bpd)	1,346		
NOARK system:			
Average Ozark Gas Transmission throughput volume (mcfd)	326,651	249,581	255,777

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(1) Mcf represents thousand cubic feet; Mcfd represents thousand cubic feet per day; Bpd represents barrels per day.

(2) 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 acquisition, through December 31, 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenue. Natural gas and liquids revenue was $761.1 million for the year ended December 31, 2007, an increase of $369.7 million from $391.4 million for the prior year. The increase was primarily attributable to revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $344.2 million, an increase of $26.5 million from the Elk City/Sweetwater system due primarily to an increase in volumes, which includes processing volumes from the newly constructed Sweetwater gas plant, and an increase of $18.5 million from the Velma system due primarily to an increase in volumes. These increases were partially offset by a decrease of $21.0 million from the NOARK system due primarily to lower natural gas sales volumes on its gathering systems. Processed natural gas volume on the Chaney Dell system was 253.5 MMcfd for the period from July 27, 2007, the date of acquisition, to December 31, 2007, while the Midkiff/Benedum system had processed natural gas volume of 103.6 MMcfd for the same period. Processed natural gas volume on the Elk City/Sweetwater system averaged 225.8 MMcfd for the year ended December 31, 2007, an increase of 46.6% from the prior year. Processed natural gas volume averaged 60.5 MMcfd on the Velma system for the year ended December 31, 2007, an increase of 4.2% from the prior year. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Critical Accounting Policies and Estimates .

Transportation, compression and other fee revenue increased to $81.8 million for the year ended December 31, 2007 compared with $60.9 million for the prior year. This $20.9 million increase was primarily due to an increase of $10.4 million from the transportation revenues associated with the NOARK system, $4.0 million of contributions from the Chaney Dell and Midkiff/Benedum systems, a $3.5 million increase from the Appalachia system, and an increase of $2.9 million associated with the Elk City/Sweetwater system. For the NOARK system, average Ozark Gas Transmission volume was 326.7 MMcfd for the year ended December 31, 2007, an increase of 30.9% from the prior year. The Appalachia system s average throughput volume was 68.7 MMcfd for the year ended December 31, 2007 as compared with 61.9 MMcfd for the prior year, an increase of 6.8 MMcfd or 11.0%. The Appalachia system s average transportation rate was $1.35 per Mcf for the year ended December 31, 2007 compared with $1.34 per Mcf for the prior year, an increase of $0.01 per Mcf. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system and throughput associated with the acquisition of a processing plant and gathering system in August 2007.

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Other income (loss), including the impact of non-cash gains and losses recognized on derivatives, was a loss of $174.1 million for the year ended December 31, 2007, a decrease of $186.5 million from the prior year. This decrease was due primarily to a $169.4 million non-cash derivative loss for the year ended December 31, 2007 compared with a $5.7 million non-cash derivative gain for the year ended December 31, 2006, an unfavorable movement of $175.2 million. This change in non-cash derivatives was the result of commodity price movements and their unfavorable impact on derivative contracts we have for production volumes in future periods. We recorded $130.2 million of non-cash derivative losses during the fourth quarter 2007, when forward crude oil prices for the duration of our derivative contracts, which are the basis for adjusting the fair value of our derivative contracts, increased from an average price of $74.78 per barrel at September 30, 2007 to $89.89 per barrel at December 31, 2007, an increase of $15.11. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Critical Accounting Policies and Estimates .

Costs and Expenses. Natural gas and liquids cost of goods sold of $587.5 million and plant operating expenses of $34.7 million for the year ended December 31, 2007 represented increases of $253.2 million and $18.9 million, respectively, from the prior year amounts due primarily to contribution from the Chaney Dell and Midkiff/Benedum acquisition and an increase in gathered and processed natural gas volumes on the Elk City/Sweetwater system, which includes contributions from the Sweetwater processing facility, partially offset by a decrease in the NOARK gathering system natural gas purchases. Transportation and compression expenses increased $2.7 million to $13.5 million for the year ended December 31, 2007 due to higher NOARK and Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections.

General and administrative expenses, including amounts reimbursed to affiliates, increased $38.4 million to $61.0 million for the year ended December 31, 2007 compared with $22.6 million for the prior year. This increase was mainly due to a $30.0 million increase in non-cash compensation expense related to vesting of phantom and common unit awards (see Note 13 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data) and higher costs associated with managing our business, including management time related to acquisition and capital raising opportunities.

Depreciation and amortization increased to $51.0 million for the year ended December 31, 2007 compared with $23.0 million for the year ended December 31, 2006 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets and our expansion capital expenditures incurred between the periods, including the Sweetwater processing facility.

Interest expense increased to $61.5 million for the year ended December 31, 2007 as compared with $24.6 million for the prior year. This $36.9 million increase was primarily due to interest associated with the $830.0 million term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems and a $5.1 million increase in the amortization of deferred finance costs principally due to $5.0 million of accelerated amortization associated with the replacement of our previous credit facility with a new credit facility in July 2007 (see Term Loan and Credit Facility).

Minority interest expense of $3.9 million for the year ended December 31, 2007 represents Anadarko s 5% ownership interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems. Minority interest expense of $0.1 million for the year ended December 31, 2006 represents Southwestern s 25% ownership interest in the net income of NOARK through May 2, 2006, the date which we acquired this remaining ownership interest.

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During June 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 the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively. Our management believes that the impact of these adjustments is immaterial to its prior financial statements.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Revenue. Natural gas and liquids revenue was $391.4 million for the year ended December 31, 2006, an increase of $52.7 million from $338.7 million for the prior year. The increase was attributable to revenue contributions of $28.2 million from the NOARK system, of which a 75% ownership interest was acquired in October 2005 and the remaining 25% ownership interest was acquired in May 2006, of $51.2 million from the Elk City system, which was acquired in April 2005, partially offset by a decrease from the Velma system of $26.7 million due principally to a decrease in natural gas prices and lower processed volume. Processed natural gas volume averaged 58.1 MMcfd on the Velma system for the year ended December 31, 2006, a decrease of 7.0% from the prior year due to the expiration of a short-term low-margin gathering and processing agreement. The impact of Velma s processed volume decline on total revenue was partially offset by an increase in the recovery percentage of NGLs at the Velma plant compared with the prior year. Gross natural gas gathered on the Elk City system averaged 277.1 MMcfd for the year ended December 31, 2006, a 10.5% increase from the prior year. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Critical Accounting Policies and Estimates .

Transportation, compression, and other fee revenue increased to $60.9 million for the year ended December 31, 2006 from $30.3 million for the prior year. This $30.6 million increase was primarily due to contributions from the transportation revenues associated with the NOARK system of $19.3 million and the Elk City system of $5.4 million and increases in the Appalachia system average transportation rate earned and volume of natural gas transported. For the NOARK system, average Ozark Gas Transmission throughput volume was 249.6 MMcfd for the year ended December 31, 2006. The Appalachia system s average throughput volume was 61.9 MMcfd for the year ended December 31, 2006 as compared with 55.2 MMcfd for the year ended December 31, 2005, an increase of 6.7 MMcfd or 12.1%. The Appalachia system s average transportation rate was $1.34 per Mcf for the year ended December 31, 2006 as compared with $1.21 per Mcf for the prior year, an increase of $0.13 per Mcf. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system and the completion of a capacity expansion project in 2005 on certain sections of our pipeline system.

Other income, including the impact of gains and losses recognized on derivatives, was $12.4 million for the year ended December 31, 2006, an increase of $9.9 million from the prior year. This increase was mainly due to a $4.1 million increase in the gain recognized on the change in market value of our non-qualifying derivatives and the ineffective portion of our qualifying derivatives, $2.7 million gain from the sale of certain gathering pipelines within the Velma system during 2006 for cash proceeds of $7.5 million and a $2.9 million gain from an insurance claim settlement related to fire damage at a Velma compressor station sustained during 2006.

Costs and Expenses. Natural gas and liquids cost of goods sold of $334.3 million and plant operating expenses of $15.7 million for the year ended December 31, 2006 represented increases of $46.1 million and $5.1 million, respectively, from the prior year amounts due primarily to the acquisitions of NOARK and Elk City, partially offset by a decrease from the Velma system due to a decline in natural gas prices and lower volume resulting from the expiration of a short-term low-margin gathering and processing agreement. Transportation and compression expenses increased $6.8 million to $10.8 million for the year ended December 31, 2006 due mainly to NOARK system operating costs and higher Appalachia system operating costs as a result of compressors added during 2005 in connection with our capacity expansion project and higher maintenance expense as a result of additional wells connected to our gathering system.

General and administrative expenses, including amounts reimbursed to affiliates, increased $9.0 million to $22.6 million for the year ended December 31, 2006 compared with $13.6 million for the prior year. This increase was mainly due to a $1.6 million increase in non-cash compensation expense related to vesting of phantom and common unit awards and higher costs associated with managing our business, including management time related to our NOARK and Elk City acquisitions and capital raising opportunities. Depreciation and amortization increased to $23.0 million for the year ended December 31, 2006 compared with $14.0 million for the prior year due primarily to the depreciation and amortization associated with the NOARK and Elk City assets acquired.

Depreciation and amortization increased to $23.0 million for the year ended December 31, 2006 compared with $14.0 million for the year ended December 31, 2005 due primarily to the depreciation associated with our expansion capital expenditures incurred between the periods, including the Sweetwater processing facility.

Interest expense increased to $24.6 million for the year ended December 31, 2006 as compared with $14.2 million for the prior year. This $10.4 million increase was primarily due to interest associated with our May 2006 and December 2005 issuances of 10-year senior unsecured notes, partially offset by a decrease in interest associated with borrowings under our credit facility and a $2.5 million increase in interest cost capitalized principally attributable to the construction of the Sweetwater plant.

Minority interest expense of $0.1 million and $1.1 million for the years ended December 31, 2006 and 2005 represents Southwestern s 25% ownership interest in the net income of NOARK from the date of acquisition of our initial 75% ownership interest on October 31, 2005 through the date of our acquisition of the remaining 25% ownership interest on May 2, 2006. Our financial results include the consolidated financial statements of NOARK from the date of its acquisition on October 31, 2005.

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 borrowings; and
- debt principal payments through additional borrowings as they become due or by the issuance of additional limited partner units.

At December 31, 2007, we had $105.0 million outstanding under our new $300.0 senior secured credit facility and $9.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $185.9 million of remaining committed capacity under the new credit facility, subject to covenant limitations (see Term Loan and Credit Facility). In addition to the availability under the credit facility, we have a universal shelf registration statement on file with the Securities and Exchange Commission, which allows us to issue equity or debt securities (see Shelf Registration Statement), of which $352.1 million remains available at December 31, 2007. At December 31, 2007, we had a working capital deficit of $78.2 million compared with $1.2 million working capital surplus at December 31, 2006. This decrease was primarily due to an increase in the current portion of our net hedge liability between periods, which is the result of changes in commodity prices after we entered into the hedges. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, unitholder distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cashflow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings and the issuance of additional limited partner units.

Cash Flows Year Ended December 31, 2007 Compared to Year December 31, 2006

Net cash provided by operating activities of $99.8 million for the year ended December 31, 2007 represented an increase of $54.8 million from $45.0 million for the prior year. The increase was derived principally from a $63.3 million increase in net income excluding non-cash charges and a $6.3 million decrease in cash flow from working capital changes. This increase in net income excluding non-cash charges was principally due to the contributions from the Chaney Dell and Midkiff/Benedum systems, which were acquired in July 2007. The non-cash charges which impacted net income include a $171.7 million favorable movement in derivative non-cash gains and losses, a $30.0 million increase in non-cash compensation expense, a $28.0 million increase in depreciation and amortization and a $5.1 million increase in amortization of deferred finance costs. The movement in derivative non-cash gains and losses resulted from commodity price movements and their unfavorable impact on derivative contracts we have for future periods. The increase in non-cash compensation expense was due to an increase in common unit awards estimated by management to be issued under incentive compensation agreements to certain key employees as a result of the acquisition of the Chaney Dell and Midkiff/Benedum systems. The increase in minority interest and depreciation and amortization resulted from our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007.

Net cash used in investing activities was $2,024.6 million for the year ended December 31, 2007, an increase of $1,920.1 million from $104.5 million for the prior year. This increase was principally due to the $1,884.5 million of net cash paid for acquisition for the year ended December 31, 2007 compared with the $30.0 million for the prior year. Net cash paid for acquisition for the year ended December 31, 2007 represents the net amount paid for our acquisition of the Chaney Dell and Midkiff/Benedum systems, while the net cash paid for the prior year comparable period represents the amount paid for our acquisition of the remaining 25% ownership interest in the NOARK system. Also affecting the change in net cash used in investing activities was a $55.9 million increase in capital expenditures, a $7.0 million decrease in cash proceeds received from the sale of assets, and a $1.5 million decrease in net cash proceeds received from APL s settlement of an insurance claim which occurred during the prior year. The decrease in cash proceeds received from the sale of assets resulted from the sale of certain gathering pipelines within the Velma system during the year ended December 31, 2006. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $1,935.1 million for the year ended December 31, 2007, an increase of $1,908.1 million from $27.0 million of net cash provided by financing activities for the prior year. This increase was principally due to a $1,095.4 million increase in net proceeds from the issuance of our common units, a $789.1 million increase in net proceeds from the issuance of long-term debt, a $39.0 million favorable impact regarding repayments of long-term debt, and a $21.9 million increase in capital contributions. These amounts were partially offset by a $39.9 million decrease in net proceeds from the issuance of our

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cumulative convertible preferred units, an $8.5 million increase in preferred unit distributions paid, and a $38.5 million net increase in borrowings under our revolving credit facility. The increase in net proceeds from the issuance of our common units, net proceeds from the issuance of our long-term debt, and capital contributions resulted from transactions undertaken during July 2007 to finance our acquisition of the Chaney Dell and Midkiff/Benedum systems.

Cash Flows Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Net cash provided by operating activities of $45.0 million for the year ended December 31, 2006 represented a decrease of $4.5 million from $49.5 million for the prior year. The decrease was derived principally from a $15.2 million decrease in cash flows resulting from changes in the components of working capital, partially offset by an $11.7 million increase in net income excluding non-cash charges. The decrease in cash resulting from changes in the components of working capital was due to additional working capital required to support the growth of our operations, including NOARK and Elk City. The increase in net income excluding non-cash charges was principally due to the full-year contributions from the acquisitions of NOARK, which was acquired in October 2005, and Elk City, which was acquired in April 2005. The non-cash charges which impacted net income include a $9.0 million increase in depreciation and amortization, a $2.9 million gain recognized on the settlement of an insurance claim for which the cash received at December 31, 2006 was recorded within cash flows from investing activities and a $2.8 million increase in gains recognized on sales of assets for which the cash received was recorded within cash flows from investing activities.

Net cash used in investing activities was $104.5 million for the year ended December 31, 2006, a decrease of $305.1 million from $409.6 million for the prior year. This decrease was principally due to a $328.8 million decrease in net cash paid for acquisitions and a $7.5 million increase in cash proceeds from the sale of assets and $1.5 million in cash proceeds from the settlement of an insurance claim, partially offset by a $32.6 million increase in capital expenditures. Net cash paid for acquisitions in 2006 consisted of the acquisition of the remaining 25% ownership interest in NOARK, while net cash paid for acquisitions in 2005 consisted of the acquisitions of Elk City and the initial 75% ownership interest in NOARK. See further discussion of capital expenditures under Capital Requirements.

Net cash provided by financing activities was $27.0 million for the year ended December 31, 2006, a decrease of $349.1 million from $376.1 million for the prior year. This decrease was principally due to a $206.5 million decrease in net proceeds from the issuance of senior notes, a $193.0 million decrease in net proceeds received from the issuance of common units, a $38.3 million increase in repayment of debt, and a $25.6 million increase in cash distributions to common limited partners and the general partner. These amounts were partially offset by a $73.3 million increase in net borrowings during the period under our credit facility and a $39.9 million increase in net proceeds from the issuance of cumulative convertible preferred units. The changes in net proceeds from the issuance of common units, preferred units, and senior notes and borrowing activity under our credit facility principally relate to the construction of the Sweetwater gas plant, a new natural gas processing plant in Oklahoma which initiated operations at the end of the third quarter of 2006, and financing the acquisitions of Elk City in April 2005, the 75% ownership interest in NOARK in October 2005, and the remaining 25% ownership interest in NOARK in May 2006. The increase in cash distributions to common limited partners and the general partner is due mainly to increases in our limited partner units outstanding and our cash distribution amount per common limited partner unit.

Capital Requirements

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

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

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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,		
	2007	2006	2005
Maintenance capital expenditures	$ 9,115	$ 4,649	$ 1,922
Expansion capital expenditures	143,775	79,182	50,576
Total	$ 152,890	$ 83,831	$ 52,498

Expansion capital expenditures increased to $143.8 million for the year ended December 31, 2007, due principally to expansions of the Appalachia, Velma and Elk City/Sweetwater, NOARK, Chaney Dell and Midkiff/Benedum gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Maintenance capital expenditures the year ended December 31, 2007 increased to $9.1 million due to the additional maintenance requirements of our Chaney Dell and Midkiff/Benedum acquisition and fluctuations in the timing of scheduled maintenance activity. As of December 31, 2007, we are committed to expend approximately $168.4 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Expansion capital expenditures increased to $79.2 million for the year ended December 31, 2006, due principally to expansions of the Appalachia, Velma and Elk City gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Expansion capital expenditures for our Mid-Continent region also included approximately $26.1 million related to the construction of the Sweetwater gas plant. Maintenance capital expenditures for the year ended December 31, 2006 increased to $4.6 million due to the additional maintenance requirements of the NOARK and Elk City acquisitions.

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, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our general partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common 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%

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of the aggregate amount of cash being distributed. During July 2007, our general partner, the holder of all of our incentive distribution rights, had agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. The general partner s incentive distributions declared for the year ended December 31, 2007, after the allocation of $9.9 million of its incentive distribution rights to us, were $15.9 million.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2007 (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	$ 1,229,426	$ 34	$	$	$ 1,229,392
Interest on total debt[1]	652	94	189	189	180
Derivative-based obligations	229,513	110,867	115,694	2,952	
Capital leases	40	40			
Operating leases	9,357	4,120	3,135	1,993	109
Total contractual cash obligations	$ 1,468,988	$ 115,155	$ 119,018	$ 5,134	$ 1,229,681

(1) Based on the interest rates of our respective debt components as of December 31, 2007.

		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	$ 9,091	$ 9,091	$	$	$
Other commercial commitments	168,352	168,352			
Total commercial commitments	$ 177,443	$ 177,443	$	$	$

Other commercial commitments relate to commitments for pipeline extensions, compressor station upgrades and processing facility upgrades.

Common Equity Offerings

In July 2007, we sold 25.6 million common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25.6 million common units sold, 3.8 million were purchased by AHD for $168.8 million. We also received a capital contribution from AHD of $23.1 million in order for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the sale to partially fund the Chaney Dell and Midkiff/Benedum acquisitions (see Significant Acquisitions).

The common units we sold in the July 2007 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that we would (a) file a registration statement with the Securities and Exchange Commission for the common units by November 24, 2007 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by March 2, 2008. On November 28, 2007, the registration statement we filed with the Securities and Exchange Commission for the common units subject to the registration rights agreement was declared effective, thereby fulfilling the requirements of the registration rights agreement.

In May 2006, we sold 0.5 million common units to Wachovia Securities, which then offered the common units to public investors. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale to partially repay borrowings under our credit facility made in connection with our acquisition of the remaining 25% ownership interest in NOARK.

In November 2005, we sold 2.7 million of our common units in a public offering for gross proceeds of $113.4 million. In addition, pursuant to an option granted to the underwriters of the offering, we sold an additional 0.3 million common units in December 2005 for gross proceeds of $13.9 million, resulting in aggregate total gross proceeds of $127.3 million. The units, which were issued under our previously filed shelf registration statement, resulted in total net proceeds of approximately $121.0 million, after underwriting commissions and other transaction costs. We primarily utilized the net proceeds from the sale to repay a portion of the amounts due under our credit facility.

In June 2005, we sold 2.3 million common units in a public offering for total gross proceeds of $96.5 million. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $91.7 million, after underwriting commissions and other transaction costs. We primarily utilized the net proceeds from the sale to repay a portion of the amounts due under our credit facility.

Shelf Registration Statement

We have an effective shelf registration statement with the Securities and Exchange Commission that permits us to periodically issue equity and debt securities for a total value of up to $500.0 million. As of December 31, 2007, $352.1 million remains available for issuance under the shelf registration statement. However, the amount, type and timing of any offerings will depend upon, among other things, our funding requirements, prevailing market conditions, and compliance with our credit facility covenants.

Private Placement of Convertible Preferred Units

On March 13, 2006, we entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. We also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital for $10.0 million on May 19, 2006, pursuant to our right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date our common units. On April 18, 2007, we and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of our common units as of the date of the notice of conversion. We may elect to pay cash rather than issue common units in satisfaction of a conversion request. We have the right to call the preferred units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.82. In consideration of Sunlight Capital s consent to the amendment of the preferred units, we issued $8.5 million of 8.125% senior unsecured notes due 2015 (the Notes) to Sunlight Capital. We recorded the Notes as long-term debt and a preferred unit dividend within partners capital. We have also reduced net income attributable to common limited partners and the general partner by $3.8 million of the $8.5 million preferred unit dividend, which is the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on our consolidated statements of operations.

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The net proceeds from the initial issuance of the preferred units were used to fund a portion of our capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under our credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

Term Loan and Credit Facility

We have a credit facility comprised of an $830.0 million senior secured term loan (term loan) which matures in July 2014 and a $300.0 million senior secured revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at December 31, 2007 was 7.2%, and the weighted average interest rate on the outstanding term loan borrowings at December 31, 2007 was 7.6%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $9.1 million was outstanding at December 31, 2007. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet. 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, and by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are in compliance with these covenants as of December 31, 2007. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt or equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with the new credit facility, we agreed to remit an underwriting fee to the lead underwriting bank of the credit facility of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. In January 2008, we and the underwriting bank agreed to extend the agreement through June 30, 2008.

The events which constitute an event of default for our credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.5 to 1.0, increasing to 2.75 to 1.0 commencing September 30, 2008. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of December 31, 2007, our ratio of funded debt to EBITDA was 4.4 to 1.0 and our interest coverage ratio was 3.1 to 1.0.

Senior Notes

At December 31, 2007, we have $293.5 million of 10-year, 8.125% senior unsecured notes due 2015 (Senior Notes) outstanding, net of unamortized premium received of $0.9 million. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, we may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes 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. On April 18, 2007, we issued Sunlight Capital $8.5 million of our Senior Notes in consideration of its consent to the amendment of our preferred units agreement.

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The indenture governing the Senior Notes contains covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. We are in compliance with these covenants as of December 31, 2007.

NOARK Notes

On May 2, 2006, we acquired the remaining 25% equity ownership interest in NOARK from Southwestern. Prior to this acquisition, NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., had $39.0 million in principal amount outstanding of 7.15% notes due in 2018, which was presented as debt on our consolidated balance sheet, to be allocated severally 100% to Southwestern. In connection with the acquisition of the 25% equity ownership interest in NOARK, Southwestern acquired NOARK Pipeline Finance, L.L.C. and agreed to retain the obligation for the outstanding NOARK notes, with the result that neither we nor NOARK have any further liability with respect to such notes.

Environmental Regulation

Our operations are subject to federal, state and local laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety. We believe 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 and criminal penalties, imposition of remedial requirements, and issuance of injunctions as to future compliance or other mandatory or consensual measures. We have an ongoing environmental compliance program. However, risks of accidental leaks or spills are associated with the transportation 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 strict environmental laws and regulations and enforcement policies hereunder, 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. One trend in environmental regulation is to increase reporting obligations and place more restrictions and limitations on activities, such as emissions of 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. Increasingly strict 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 arising.

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Inflation and Changes in Prices

Inflation affects the operating expenses of our gathering systems. Increases in those expenses are not necessarily offset by increases in transportation fees that the gathering operations are able to charge. While we anticipate that inflation will affect our future operating costs, we cannot predict the timing or amounts of any such effects. In addition, the value of our gathering systems has been and will continue to be affected by changes in natural gas prices. Natural gas prices are subject to fluctuations which we are unable to control or accurately predict.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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, stock compensation, 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 we have identified are discussed below.

Use of Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 our consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. Our consolidated financial statements are based on a number of significant estimates, including the fair value of derivative instruments, stock compensation, the purchase price allocation for the acquisition of Chaney Dell and Midkiff/Benedum systems, which could affect the reported amounts for property, plant and equipment, goodwill, and other intangible assets, and other items. Actual results could differ from those estimates.

Revenue Recognition

Revenue in our Appalachia segment is recognized at the time the natural gas is transported through our gathering systems. Under the terms of our natural gas gathering agreements with Atlas Energy and its affiliates, we receive fees for gathering natural gas from wells owned by Atlas Energy and by drilling investment partnerships sponsored by Atlas Energy. The fees received for the gathering services are generally the greater of 16% of the gross sales price for natural gas produced from the wells, or $0.35 or $0.40 per Mcf, depending on the ownership of the well. Substantially all natural gas gathering revenue in our Appalachia segment is derived from these agreements. Fees for transportation services provided to independent third parties whose wells are connected to our Appalachia gathering systems are at separately negotiated prices.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, 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 or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated

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transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas received by our Elk City/Sweetwater and Chaney Dell systems, which have keep-whole contracts, is generally low in liquids content and meets 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. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

We accrue 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 our records and estimates of the related transportation and compression fees which are, in turn, based upon applicable product prices (see Use of Estimates accounting policy for further description).

Intangible Assets

At December 31, 2007 and 2006, we have intangible assets with finite lives which were recorded in connection with certain consummated acquisitions (see Note 8 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). We recorded the initial purchase price allocation for the Chaney Dell and Midkiff/Benedum acquisition on July 27, 2007. During the fourth quarter of 2007, we adjusted the preliminary purchase price allocation by increasing the estimated amount allocated to customer contracts and customer relationships and reducing amounts initially allocated to property, plant and equipment. During 2006, we adjusted the preliminary purchase price allocation for the NOARK acquisition by reducing the estimated amount allocated to customer contracts and customer relationships and allocating additional amounts to property, plant and equipment (see Note 6 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data).

Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized 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, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for our customer contract intangible assets is based upon the approximate average length of customer contracts in existence at the date of acquisition. The estimated useful life for our customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition.

Goodwill

At December 31, 2007 and 2006, we have goodwill which was recorded in connection with consummated acquisitions (see Note 8 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). We recorded the initial purchase price allocation for the Chaney Dell and Midkiff/Benedum acquisition on July 27, 2007. During the fourth quarter of 2007, we adjusted the preliminary purchase price allocation by increasing the estimated amount allocated to goodwill and reducing amounts initially allocated to property, plant and equipment. Due to the recent date of the Chaney Dell and Midkiff/Benedum acquisition, the purchase price allocation for the acquisition is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate this allocation. Unresolved items which could affect the final purchase price allocation include, among other things, the recoverability of state sales tax paid on the transaction, which has been included as an acquisition cost. The recovery of state sales tax paid on the transaction in future periods could reduce amounts allocated to goodwill. During 2006, we adjusted the preliminary purchase price allocation for the NOARK acquisition by reducing the estimated amount allocated to goodwill and allocating additional amounts to property, plant and equipment (see Note 6 to consolidated financial statements in Item 8, Financial Statements and Supplementary Data). We test our goodwill for impairment at each year end by comparing enterprise fair values to carrying values. The evaluation of impairment under SFAS No. 142 requires the use of projections, estimates and assumptions as to the future performance of our operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections, resulting in revisions to our assumptions and, if required, recognition of an impairment loss. Our test of goodwill at December 31, 2007 resulted in no impairment. We will continue to evaluate our goodwill at least annually and if impairment indicators arise, will reflect the impairment of goodwill, if any, within our consolidated statements of operations in the period in which the impairment is indicated.

Depreciation and Amortization

We calculate depreciation based on the estimated useful lives and salvage values of our assets. However, factors such as usage, equipment failure, competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Impairment of Assets

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable. We determine if our long-lived assets are impaired by comparing the carrying amount of an asset or group of assets with the estimated undiscounted future cash flows associated with such asset or group of assets. If the carrying amount is greater than the estimated undiscounted future cash flows, an impairment loss is recognized to reduce the carrying value to fair value. Our operations are subject to numerous factors which could affect future cash flows which we discuss under Item 1A, Risk Factors . We continuously monitor these factors and pursue alternative strategies to maintain or enhance cash flows associated with these assets; however, we cannot assure you that we can mitigate the effects, if any, on future cash flows related to any changes in these factors.

Fair Value of Derivative Commodity Contracts

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. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these 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. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas,

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NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133).

We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. We assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of the hedged items. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying commodity, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which we determine through utilization of market data, will be recognized immediately within other income (loss) in our consolidated statements of operations. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassify them to natural gas and liquids revenue within our consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of operations as they occur.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. The net loss in accumulated other comprehensive loss within partners capital on our consolidated balance sheet at December 31, 2007, if the fair values of the instruments remain at current market values, will be reclassified to natural gas and liquids revenue in our consolidated statements of operations in future periods. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, we signed definitive agreements to acquire control of the Chaney Dell and Midkiff/Benedum systems (see Significant Acquisitions). In connection with agreements entered into with respect to our new credit facility and private placement of common units, we agreed as a condition precedent to closing that we would hedge 80% of our projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, we entered into derivative instruments to hedge 80% of the projected production of the Anadarko Assets to be acquired as required under the financing agreements. The production volume of the Anadarko Assets was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Anadarko Assets had not yet been completed. Accordingly, we recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in our consolidated statements of operations. We recognized a non-cash loss of $18.8 million related to the change in value of derivatives entered into specifically for the Chaney Dell and Midkiff/Benedum systems from the time the derivative instruments were entered into to the date of closing of the acquisition during the year ended December 31, 2007. Upon closing of the acquisition in July 2007, the production volume of the Anadarko Assets was considered probable forecasted production under SFAS No. 133. We designated many of these instruments as cash flow hedges and evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

In connection with the Chaney Dell and Midkiff/Benedum acquisition, we reached an agreement with Pioneer which grants Pioneer an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008 and an additional 7.4% interest beginning on June 15, 2009 (see Note 8 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). At December 31, 2007, we have received no indication that Pioneer will exercise either of its options under the agreement. If Pioneer does exercise either of these options, we will discontinue hedge accounting for the derivative instruments covering the portion of the forecasted production of the Midkiff/Benedum system sold to Pioneer and will evaluate these derivative instruments to determine if they can be documented to match other forecasted production we may have.

During December 2007, we discontinued hedge accounting for crude oil derivative instruments covering certain forecasted condensate production for 2008 and other future periods, and then documented these derivative instruments to match certain forecasted NGL production for the respective periods. The discontinuation of hedge accounting for these instruments with regard to our condensate production resulted in a $12.6 million non-cash derivative loss recognized within other income (loss) in our consolidated statements of operations and a corresponding decrease in accumulated other comprehensive loss in partners capital in our consolidated balance sheet.

A portion of our future natural gas, NGL and condensate sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to natural gas and liquids revenue within our consolidated statements of operations.

Volume Measurement

We record amounts for natural gas gathering and transportation revenue, NGL transportation and processing revenue, natural gas sales and natural gas purchases, and the sale of production based on volume and energy measurements. Variances resulting from such calculations, while within recognized industry tolerances, are inherent in our business.

Stock Compensation

We adopted SFAS No. 123(R), Share-Based Payment, as revised (SFAS No. 123(R)), as of December 31, 2005. Generally, the approach to accounting in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

Prior to the adoption of SFAS No. 123(R), we followed Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and its interpretations (collectively referred to as APB No. 25), which SFAS No. 123(R) superseded. APB No. 25 allowed for valuation of share-based payments to employees at their intrinsic values. Under this methodology, we recognized compensation expense for phantom units granted only if the current market price of the underlying units exceeded the exercise price. Since the inception of our Long-Term Incentive Plan, we have only granted phantom units with no exercise price and, as such, recognized compensation expense based upon the market price of our limited partner units at the date of grant. Since we have historically recognized compensation expense for our share-based payments at their fair values, the adoption of SFAS No. 123(R) did not have a material impact on its consolidated financial statements.

Long-Term Incentive Plan. We have a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through December 31, 2007.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant 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 we make on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase our common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through December 31, 2007, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. 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 LTIP. All units outstanding under the LTIP at December 31, 2007 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs are recorded as reductions of Partners Capital on the consolidated balance sheet.

Incentive Compensation Agreements. We have incentive compensation agreements which have granted awards to certain key employees retained from previously consummated acquisitions. These individuals are entitled to receive our common units 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. Of the total common units to be issued under the incentive compensation agreements, 58,822 were issued during the year ended December 31, 2007. The remaining common units to be issued under the incentive compensation agreements will be determined based upon the financial performance of certain of our assets for the year ended December 31, 2008. The incentive compensation agreements also dictate that no individual covered under the agreements shall receive an amount of common units in excess of one percent of our outstanding common units at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of our outstanding common units shall be paid in cash.

The ultimate number of common units estimated to be issued under the incentive compensation agreements will be determined by the financial performance of certain of our assets for the year ended December 31, 2008. The vesting period for such awards concluded on September 30, 2007 and all compensation expense related to the awards was recorded as of that date. We anticipate that adjustments will be recorded in future periods with respect to the awards under the incentive compensation agreements based upon the actual financial performance of the assets in future periods in comparison to their estimated performance.

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 financial 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, 2007. Only the potential impact of hypothetical assumptions are analyzed. The analysis does not consider other possible effects that could impact our business.

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Interest Rate Risk. At December 31, 2007, we had a $300.0 million senior secured revolving credit facility ($105.0 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. We also had an $830.0 million senior secured term loan outstanding at December 31, 2007, of which the net proceeds were utilized to partially finance our acquisition of control of the Chaney Dell and Midkiff/Benedum systems. The weighted average interest rate for the revolving credit facility borrowings was 7.2% at December 31, 2007, and the weighted average interest rate for the term loan borrowings was 7.6% at December 31, 2007. During January 2008, we entered into interest rate derivative contracts having an aggregate notional principal amount of $200.0 million. Under the terms of this agreement, we will pay 2.88%, plus the applicable margin as defined under the terms of our credit facility, and will receive LIBOR plus the applicable margin, on the notional principal amount of $200.0 million. This hedge effectively converts $200.0 million of the Partnership s floating rate debt under the credit facility to fixed-rate debt. The interest rate swap agreement begins on January 31, 2008 and expires on January 31, 2010. Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our interest expense by $7.4 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our gross margin for the twelve-month period ending December 31, 2008 of approximately $3.7 million.

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. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these 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. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133).

We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. We assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of the hedged production. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying commodity, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which we determine through utilization of market data, will be recognized immediately within other income (loss) in our consolidated statements of operations. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassify them to natural gas and liquids revenue within our consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of operations as they occur.

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Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. At December 31, 2007 and 2006, we reflected net derivative liabilities on our consolidated balance sheets of $229.5 million and $20.1 million, respectively. Of the $62.1 million of net loss in accumulated other comprehensive loss within partners capital on our consolidated balance sheet at December 31, 2007, if the fair values of the instruments remain at current market values, we will reclassify $43.1 million of losses to natural gas and liquids revenue in our consolidated statements of operations over the next twelve month period as these contracts expire, and $19.0 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, we signed definitive agreements to acquire control of the Chaney Dell and Midkiff/Benedum systems (see Significant Acquisitions). In connection with agreements entered into with respect to our new credit facility, term loan and private placement of common units, we agreed as a condition precedent to closing that we would hedge 80% of our projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, we entered into derivative instruments to hedge 80% of the projected production of the Anadarko Assets to be acquired as required under the financing agreements. The production volume of the Anadarko Assets was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Anadarko Assets had not yet been completed. Accordingly, we recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in our consolidated statements of operations. We recognized a non-cash loss of $18.8 million related to the change in value of derivatives entered into specifically for the Chaney Dell and Midkiff/Benedum systems from the time the derivative instruments were entered into to the date of closing of the acquisition during the year ended December 31, 2007. Upon closing of the acquisition in July 2007, the production volume of the Anadarko Assets was considered probable forecasted production under SFAS No. 133. We designated many of these instruments as cash flow hedges and evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

In connection with the Chaney Dell and Midkiff/Benedum acquisition, we reached an agreement with Pioneer which grants Pioneer an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008 and an additional 7.4% interest beginning on June 15, 2009 (see Note 8 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). At December 31, 2007, we have received no indication that Pioneer will exercise either of its options under the agreement. If Pioneer does exercise either of these options, we will discontinue hedge accounting for the derivative instruments covering the portion of the forecasted production of the Midkiff/Benedum system sold to Pioneer and we will evaluate these derivative instruments to determine if they can be documented to match other forecasted production we may have.

During December 2007, we discontinued hedge accounting for crude oil derivative instruments covering certain forecasted condensate production for 2008 and other future periods, and then documented these derivative instruments to match certain forecasted NGL production for the respective periods. The discontinuation of hedge accounting for these instruments with regard to our condensate production resulted in a $12.6 million non-cash derivative loss recognized within other income (loss) in our consolidated statements of operations and a corresponding decrease in accumulated other comprehensive loss in partners capital in our consolidated balance sheet.

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The following table summarizes our derivative activity for the periods indicated (amounts in thousands):

	Years ended December 31,		
	2007	2006	2005
Loss from cash settlement of qualifying hedge instruments[(1)]	$ (49,393)	$ (13,945)	$ (11,125)
Gain/(loss) from change in market value of non- qualifying derivatives[(2)]	(153,363)	4,206	
Gain/(loss) from de-designation of cash flow derivatives[(2)]	(12,611)		
Gain/(loss) from change in market value of ineffective portion of qualifying derivatives[(2)]	(3,450)	1,520	1,625
Loss from cash settlement of non-qualifying derivatives[(2)]	(10,158)		

(1) Included within natural gas and liquids revenue on our consolidated statements of operations.
(2) Included within other income (loss) on our consolidated statements of operations.

A portion of our future natural gas, NGL and condensate sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to natural gas and liquids revenue within our consolidated statements of operations.

As of December 31, 2007, we had the following NGLs, natural gas, and crude oil volumes hedged, including derivatives that do not qualify for hedge accounting:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[(1)] (in thousands)
2008	61,362,000	$ 0.706	$ (29,435)
2009	8,568,000	0.746	(4,189)
			$ (33,624)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)[(2)] (in thousands)	Option Type
2008	4,173,600	279,347,544	$ 60.00	$ 852	Puts purchased
2008	4,173,600	279,347,544	79.23	(55,674)	Calls sold
2009	5,184,000	354,533,760	60.00	5,216	Puts purchased
2009	5,184,000	354,533,760	78.88	(64,031)	Calls sold
2010	3,127,500	213,088,050	61.08	5,638	Puts purchased
2010	3,127,500	213,088,050	81.09	(35,442)	Calls sold
2011	606,000	34,869,240	70.59	2,681	Puts purchased
2011	606,000	34,869,240	95.56	(3,924)	Calls sold
2012	450,000	25,893,000	70.80	2,187	Puts purchased
2012	450,000	25,893,000	97.10	(2,922)	Calls sold

	$	(145,419)

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Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Asset/(Liability)(2) (in thousands)
2008	5,484,000	$ 8.795	$ 5,397
2009	5,724,000	8.611	538
2010	4,560,000	8.526	(351)
2011	2,160,000	8.270	(607)
2012	1,560,000	8.250	(331)
			$ 4,646

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Asset/(Liability)(2) (in thousands)
2008	5,484,000	$ (0.727)	$ 187
2009	5,724,000	(0.558)	828
2010	4,560,000	(0.622)	221
2011	2,160,000	(0.664)	(32)
2012	1,560,000	(0.601)	47
			$ 1,251

Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Asset/(Liability)(2) (in thousands)
2008	16,260,000	$ 8.978(4)	$ (18,575)
2009	15,564,000	8.680	(2,542)
2010	8,940,000	8.580	464
2011	2,160,000	8.270	607
2012	1,560,000	8.250	331
			$ (19,715)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability(2)

	(mmbtu)(3)	(per mmbtu)(3)	(in thousands)
2008	16,260,000	$ (1.114)	$ (194)
2009	15,564,000	(0.654)	(6,152)
2010	8,940,000	(0.600)	(2,337)
2011	2,160,000	(0.700)	(89)
2012	1,560,000	(0.610)	(64)
			$ (8,836)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(2) (in thousands)
2008	65,400	$ 59.424	$ (2,234)
2009	33,000	62.700	(842)
			$ (3,076)

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Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)[2] (in thousands)	Option Type
2008	262,800	$ 60.000	$ (42)	Puts purchased
2008	262,800	78.174	(11,149)	Calls sold
2009	306,000	60.000	807	Puts purchased
2009	306,000	80.017	(9,072)	Calls sold
2010	234,000	61.795	835	Puts purchased
2010	234,000	83.027	(5,283)	Calls sold
2011	30,000	60.000	272	Puts purchased
2011	30,000	74.500	(724)	Calls sold
2012	30,000	60.000	195	Puts purchased
2012	30,000	73.900	(579)	Calls sold
			$ (24,740)	
		Total net liability	$ (229,513)	

(1) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

(2) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

(3) Mmbtu represents million British Thermal Units.

(4) Includes the Partnership s premium received from its sale of an option for it to sell 936,000 mmbtu of natural gas at an average price of $15.50 per mmbtu for the year ended December 31, 2008.

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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) and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atlas Pipeline Partners, L.P. s internal control over financial reporting as of December 31, 2007, 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 27, 2008 expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 27, 2008

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,980	$ 1,795
Accounts receivable affiliates	3,334	7,601
Accounts receivable	147,360	51,192
Current portion of derivative asset		5,437
Prepaid expenses and other	14,749	10,444
Total current assets	177,423	76,469
Property, plant and equipment, net	1,748,661	607,097
Long-term derivative asset		305
Intangible assets, net	219,203	25,530
Goodwill	709,283	63,441
Minority interest	2,163	
Other assets, net	20,881	14,042
	$ 2,877,614	$ 786,884
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 34	$ 71
Accounts payable	20,530	18,624
Accrued liabilities	43,487	6,410
Current portion of derivative liability	110,867	17,362
Accrued producer liabilities	80,698	32,766
Total current liabilities	255,616	75,233
Long-term derivative liability	118,646	8,505
Long-term debt, less current portion	1,229,392	324,012
Commitments and contingencies		
Partners capital:		
Preferred limited partner s interest	37,076	39,381
Common limited partners interests	1,269,521	350,805
General partner s interest	29,413	11,034
Accumulated other comprehensive loss	(62,050)	(22,086)
Total partners capital	1,273,960	379,134
	$ 2,877,614	$ 786,884

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, 2007	2006	2005
Revenue:			
Natural gas and liquids	$ 761,118	$ 391,356	$ 338,672
Transportation, compression and other fees affiliates	33,169	30,189	24,346
Transportation, compression and other fees third parties	48,616	30,735	5,963
Other income (loss)	(174,103)	12,412	2,519
Total revenue and other income (loss)	668,800	464,692	371,500
Costs and expenses:			
Natural gas and liquids	587,524	334,299	288,180
Plant operating	34,667	15,722	10,557
Transportation and compression	13,484	10,753	4,053
General and administrative	55,047	20,250	11,825
Compensation reimbursement affiliates	5,939	2,319	1,783
Depreciation and amortization	50,982	22,994	13,954
Interest	61,526	24,572	14,175
Minority interests	3,940	118	1,083
Other			138
Total costs and expenses	813,109	431,027	345,748
Net income (loss)	(144,309)	33,665	25,752
Preferred unit dividend effect	(3,756)		
Preferred unit imputed dividend cost	(2,494)	(1,898)	
Net income (loss) attributable to common limited partners and the general partner	$ (150,559)	$ 31,767	$ 25,752
Allocation of net income (loss) attributable to common limited partners and the general partner:			
Common limited partners interest	$ (163,071)	$ 16,558	$ 16,355
General partner s interest	12,512	15,209	9,397
Net income (loss) attributable to common limited partners and the general partner	$ (150,559)	$ 31,767	$ 25,752
Net income (loss) attributable to common limited partners per unit:			
Basic	$ (6.75)	$ 1.29	$ 1.86
Diluted	$ (6.75)	$ 1.27	$ 1.84
Weighted average common limited partner units outstanding:			
Basic	24,171	12,884	8,808
Diluted	24,171	13,053	8,872

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,		
	2007	**2006**	**2005**
Net income (loss)	$ (144,309)	$ 33,665	$ 25,752
Preferred unit dividend effect	(3,756)		
Preferred unit imputed dividend cost	(2,494)	(1,898)	
Net income (loss) attributable to common limited partners and the general partner	(150,559)	31,767	25,752
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges	(101,968)	(5,956)	(39,882)
Reclassification adjustment to earnings for de-designation of cash flow hedges	12,611		
Add: adjustment for realized losses reclassified to net income (loss)	49,393	13,945	11,125
Total other comprehensive income (loss)	(39,964)	7,989	(28,757)
Comprehensive income (loss)	$ (190,523)	$ 39,756	$ (3,005)

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Limited Partner Units								
	Preferred	**Common**	**Subordinated**	**Preferred Limited Partner**	**Common Limited Partners**	**Subordinated Limited Partner**	**General Partner**	**Accumulated Other Comprehensive Income (Loss)**	**Total Partners Capital**
Balance at January 1, 2005		5,563,659	1,641,026	$	$ 135,873	$ (104)	$ 2,253	$ (1,318)	$ 136,704
Conversion of subordinated units		1,641,026	(1,641,026)		(104)	104			
Issuance of common units in public offering		5,330,000			212,700				212,700
Issuance of common units under incentive plans		14,581							
General partner capital contributions							4,684		4,684
Unissued common units under incentive plans					5,381				5,381
Distributions to partners					(20,433)		(6,240)		(26,673)
Distribution equivalent rights paid on unissued units under incentive plans					(281)				(281)
Other comprehensive loss								(28,757)	(28,757)
Net income					16,355		9,397		25,752
Balance at December 31, 2005		12,549,266		$	$ 349,491	$	$ 10,094	$ (30,075)	$ 329,510
Issuance of common units		500,000			19,704				19,704
Issuance of 6.5% cumulative convertible preferred limited partner units	40,000			37,483					37,483
Preferred dividend discount					2,350		48		2,398
General partner capital contribution							1,206		1,206
Unissued common units under incentive plans					6,315				6,315
Issuance of units under incentive plans		31,152							
					(43,194)		(15,523)		(58,717)

Distributions paid to common limited partners and the general partner								
Distribution equivalent rights paid on unissued units under incentive plans				(419)				(419)
Other comprehensive income							7,989	7,989
Net income			1,898	16,558		15,209		33,665
Balance at December 31, 2006	40,000	13,080,418	$ 39,381	$ 350,805	$	$ 11,034	$ (22,086)	$ 379,134
Issuance of common units		25,568,175		1,115,149				1,115,149
General partner capital contribution						23,076		23,076
Preferred unit dividend			(8,524)					(8,524)
Cost incurred related to issuance of preferred dividend			(31)					(31)
Unissued common units under incentive plans				36,346				36,346
Issuance of units under incentive plans		109,988		(40)				(40)
Distributions paid to common limited partners and the general partner				(69,084)		(17,209)		(86,293)
Distribution equivalent rights paid on unissued units under incentive plans				(584)				(584)
Other comprehensive loss							(39,964)	(39,964)
Net income (loss)			6,250	(163,071)		12,512		(144,309)
Balance at December 31, 2007	40,000	38,758,581	$ 37,076	$ 1,269,521	$	$ 29,413	$ (62,050)	$ 1,273,960

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, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (144,309)	$ 33,665	$ 25,752
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	50,982	22,994	13,954
Non-cash loss (gain) on derivative value	169,424	(2,316)	(954)
Non-cash compensation expense	36,306	6,315	4,672
Loss (gain) on asset sales and dispositions	805	(2,719)	
Gain on insurance claim settlement		(2,921)	
Amortization of deferred finance costs	7,380	2,298	2,140
Minority interests	3,940	118	1,083
Net distributions paid to minority interest holders.	(6,103)		
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable and prepaid expenses and other	(96,306)	944	(27,823)
Accounts payable and accrued liabilities	73,383	(10,397)	33,849
Accounts payable and accounts receivable affiliates	4,267	(2,952)	(3,153)
Net cash provided by operating activities	99,769	45,029	49,520
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash paid for acquisitions	(1,884,458)	(30,000)	(358,831)
Capital expenditures	(139,647)	(83,716)	(51,101)
Proceeds from insurance claim settlement		1,522	
Proceeds from sales of assets	553	7,540	
Other	(1,091)	155	325
Net cash used in investing activities	(2,024,643)	(104,499)	(409,607)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from issuance of debt	817,131	36,582	243,102
Repayment of debt		(39,019)	(677)
Borrowings under credit facility	320,500	81,000	463,500
Repayments under credit facility	(253,500)	(52,500)	(508,250)
Net proceeds from issuance of common limited partner units	1,115,149	19,704	212,700
Net proceeds from issuance of preferred limited partner units		39,881	
General partner capital contributions	23,076	1,206	4,684
Distributions paid to common limited partners and the general partner	(86,293)	(58,717)	(33,140)
Other	(1,004)	(1,109)	(5,809)
Net cash provided by financing activities	1,935,059	27,028	376,110
Net change in cash and cash equivalents	10,185	(32,442)	16,023
Cash and cash equivalents, beginning of year	1,795	34,237	18,214
Cash and cash equivalents, end of year	$ 11,980	$ 1,795	$ 34,237

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 transmission, gathering and processing of natural gas. 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. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,476,253 limited partner units in the Partnership. At December 31, 2007, the Partnership had 38,758,581 common limited partnership units and 40,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4).

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS) which owns a 64.0% ownership interest in AHD at December 31, 2007, also owns a 49.4% ownership interest in Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded partnership (NYSE: ATN). Substantially all of the natural gas the Partnership transports in the Appalachian Basin is derived from wells operated by Atlas Energy.

Certain amounts in the prior years consolidated financial statements have been reclassified to conform to the current year presentation. During June 2006, the Partnership identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, the Partnership recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively.

In August 2006, the Partnership sustained fire damage to a compressor station within the Velma region of its Mid-Continent segment. The Partnership maintains property damage and business interruption insurance for all of its assets and operating activities. During the fourth quarter of 2006, the Partnership received a $1.5 million partial settlement from its insurance providers related to this incident and reached a final settlement for an additional $2.6 million of insurance proceeds received during the first quarter of 2007. At December 31, 2006, the Partnership recorded the additional $2.6 million in prepaid expenses and other within its consolidated balance sheet and other income (loss) within its consolidated statements of operations for the insurance proceeds settlement amount.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Minority 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% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

On July 27, 2007, the Partnership acquired control of Anadarko Petroleum Corporation s (NYSE: APC) (Anadarko) 100% interest in the Chaney Dell natural gas gathering system 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 (see Note 8). The transaction was effected by the formation of two joint venture companies which own the respective systems, of which the Partnership has a 95% ownership interest and Anadarko has a 5% interest in each. The Partnership consolidates 100% of these joint ventures. The Partnership reflects Anadarko s 5% ownership interest in the net income of these joint ventures as minority interest on its statements of operations. The Partnership also reflects Anadarko s investment in the net assets of the joint ventures as minority interest on its consolidated balance sheet. In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems, the joint ventures issued cash to Anadarko of $1.9 billion in return for a note receivable. This note receivable is reflected within minority interest on the Partnership s consolidated balance sheet.

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 Midkiff/Benedum system s status as an undivided joint venture, 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.

The consolidated financial statements also include the financial statements of NOARK Pipeline System, Limited Partnership (NOARK), an entity in which the Partnership currently owns a 100% ownership interest (see Note 8). On May 2, 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Pipeline Company (Southwestern), a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Prior to this transaction, the Partnership owned a 75% ownership interest in NOARK, which it had acquired in October 2005 from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE). In connection with the acquisition of the remaining 25% ownership interest, Southwestern assumed liability for $39.0 million in principal amount outstanding of NOARK s 7.15% notes due in 2018, which had been presented as long-term debt on the Partnership s consolidated balance sheet prior to the acquisition of the remaining 25% ownership interest. Subsequent to the acquisition of the remaining 25% ownership interest in NOARK, the Partnership consolidates 100% of NOARK s financial statements. The minority interest expense reflected on the Partnership s consolidated statements of operations for the years ended December 31, 2006 and 2005 represents Southwestern s interest in NOARK s net income prior to the May 2, 2006 acquisition.

Use of Estimates

The preparation of the Partnership s consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 costs and expenses during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including the fair value of derivative instruments, stock compensation, the purchase price allocation for the acquisition of Chaney Dell and Midkiff/Benedum systems, which could affect the reported amounts for property, plant and equipment, goodwill, and other intangible assets, and other items. Actual results could differ from those estimates.

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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, 2007 and 2006, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Property, Plant and Equipment

Property and Equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Depreciation expense is recorded for each asset over its estimated useful life using the straight-line method.

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.

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 8.0%, 8.1% and 6.6% for the years ended December 31, 2007, 2006 and 2005, respectively, and the amount of interest capitalized was $3.3 million, $2.6 million and $0.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Fair Value of Financial Instruments

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair values because of the short maturities of these instruments. The fair values of these financial instruments are represented in the Partnership s consolidated balance sheets (see Note 12).

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices. The Partnership applies the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133) to its derivative instruments. SFAS No. 133 requires each derivative instrument to be recorded 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 Partnership s consolidated statements of operations unless specific hedge accounting criteria are met.

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Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions (see Note 8). The following table reflects the components of intangible assets being amortized at December 31, 2007 and 2006 (in thousands):

	December 31, 2007	December 31, 2006	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,390	8
Customer relationships	222,572	17,260	7-20
	$ 235,382	$ 29,650	
Accumulated Amortization:			
Customer contracts	$ (4,215)	$ (2,646)	
Customer relationships	(11,964)	(1,474)	
	$ (16,179)	$ (4,120)	
Net Carrying Amount:			
Customer contracts	$ 8,595	$ 9,744	
Customer relationships	210,608	15,786	
	$ 219,203	$ 25,530	

The Partnership recorded its initial purchase price allocation for the Chaney Dell and Midkiff/Benedum acquisition on July 27, 2007. During the fourth quarter of 2007, the Partnership adjusted its preliminary purchase price allocation by increasing the estimated amount allocated to customer contracts and customer relationships and reducing amounts initially allocated to property, plant and equipment. During 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships based upon the preliminary findings of an independent valuation firm and allocated additional amounts to property, plant and equipment (see Note 6 and Note 8).

SFAS No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized 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 and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition. Amortization expense on intangible assets was $12.1 million, $2.0 million and $2.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. Amortization expense related to intangible assets is estimated to be $25.6 million for each of the next five calendar years commencing in 2008.

Goodwill

At December 31, 2007 and 2006, the Partnership had $709.3 million and $63.4 million, respectively, of goodwill recorded in connection with consummated acquisitions (see Note 8). The changes in the carrying amount of goodwill for the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

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	Years Ended December 31, 2007	2006	2005
Balance, beginning of year	$ 63,441	$ 111,446	$ 2,305
Goodwill acquired (preliminary allocation) Elk City acquisition			61,136
Goodwill acquired (preliminary allocation) 75% interest in NOARK acquisition			49,088
Goodwill acquired (preliminary allocation) remaining 25% interest in NOARK acquisition		30,195	
Goodwill acquired (preliminary allocation) Chaney Dell and Midkiff/Benedum acquisition			
Reduction in minority interest deficit acquired		(118)	(1,083)
Purchase price allocation adjustment NOARK		(78,082)	
Purchase price allocation adjustment Chaney Dell and Midkiff/Benedum	645,842		
Impairment losses			
Balance, end of year	$ 709,283	$ 63,441	$ 111,446

The Partnership recorded its initial purchase price allocation for the Chaney Dell and Midkiff/Benedum acquisition on July 27, 2007. During the fourth quarter of 2007, the Partnership adjusted its preliminary purchase price allocation by increasing the estimated amount allocated to goodwill and reducing amounts initially allocated to property, plant and equipment. Due to the recent date of the Chaney Dell and Midkiff/Benedum acquisition, the purchase price allocation for the acquisition is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate this allocation. Unresolved items which could affect the final purchase price allocation include, among other things, the recoverability of state sales tax paid on the transaction, which has been included as an acquisition cost. The recovery of state sales tax paid on the transaction in future periods could reduce amounts allocated to goodwill. During 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to goodwill based upon the findings of an independent valuation firm and allocated additional amounts to property, plant and equipment (see Note 6 and Note 8). The Partnership tests its goodwill for impairment at each year end by comparing reporting unit fair values to carrying values. The evaluation of impairment under SFAS No. 142 requires the use of projections, estimates and assumptions as to the future performance of the Partnership s operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections, resulting in revisions to the Partnership s assumptions and, if required, recognition of an impairment loss. The Partnership s test of goodwill at December 31, 2007 resulted in no impairment. The Partnership will continue to evaluate its goodwill at least annually and if impairment indicators arise, will reflect the impairment of goodwill, if any, within the consolidated statement of operations for the period in which the impairment is indicated.

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.

In June 2006, the Financial Accounting Standards Board (FASB) released FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes , an Interpretation of FASB Statement No. 109 (FIN 48). FIN 48 provides guidance for how uncertain tax positions should be recognized, measured, presented and disclosed in the financial statements. FIN 48 requires the evaluation of tax positions taken or expected to be taken in the course of preparing the Partnership s tax returns to determine whether the tax positions have met a more-likely-than-not threshold of being sustained by the applicable tax authority. Tax benefits related to tax positions not deemed to meet the more-likely-than-not threshold are not permitted to be recognized in the financial statements. The provisions of FIN 48 were adopted by the Partnership effective January 1, 2007. Implementation of FIN 48 had no impact on the consolidated financial statements of the Partnership during the year ended December 31, 2007. The Partnership policy is to reflect interest and penalties related to uncertain tax positions as part of its income tax expense, when and if they become applicable.

The Partnership files income tax returns in the U.S. federal and various state jurisdictions. With limited exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2004.

Stock-Based Compensation

The Partnership adopted SFAS No. 123(R), Share-Based Payment, as revised (SFAS No. 123(R)), as of December 31, 2005. Generally, the approach to accounting in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

Prior to the adoption of SFAS No. 123(R), the Partnership followed Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and its interpretations (collectively referred to as APB No. 25), which SFAS No. 123(R) superseded. APB No. 25 allowed for valuation of share-based payments to employees at their intrinsic values. Under this methodology, the Partnership recognized compensation expense for phantom units granted only if the current market price of the underlying units exceeded the exercise price. Since the inception of its Long-Term Incentive Plan (see Note 13), the Partnership has only granted phantom units with no exercise price and, as such, recognized compensation expense based upon the market price of the Partnership s limited partner units at the date of grant. Since the Partnership has historically recognized compensation expense for its share-based payments at their fair values, the adoption of SFAS No. 123(R) did not have a material impact on its consolidated financial statements.

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, which is determined after the deduction of the general partner s and the preferred unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The general partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5), with a priority allocation of net income in an amount equal to the general partner s incentive distributions, in accordance with the partnership agreement, and the remaining net income or loss allocated with respect to the general partner s and limited partners ownership interests. Diluted net income 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 and the dilutive effect of phantom unit awards, as calculated by the treasury stock method, and the dilutive effect of convertible securities. Phantom units consist of common units issuable under the terms of the Partnership s Long-Term Incentive Plan and Incentive Compensation Agreements

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(see Note 13). The following table sets forth the reconciliation of the 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,		
	2007	2006	2005
Weighted average common limited partner units - basic	24,171	12,884	8,808
Add effect of dilutive unit incentive awards[1]		169	64
Weighted average common limited partner units - diluted	24,171	13,053	8,872

(1) For the year ended December 31, 2007, approximately 524,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

For the years ended December 31, 2007 and 2006, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1,000 par value 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 be anti-dilutive (see Note 4 for additional information regarding the conversion features of the preferred limited partner units). There were no convertible preferred limited partnership units outstanding during the year ended December 31, 2005.

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. The Partnership accounts for environmental contingencies in accordance with SFAS No. 5, Accounting for Contingencies. 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. The Partnership maintains insurance which may cover in whole or in part certain environmental expenditures. At December 31, 2007 and 2006, the Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments: natural gas transmission and gathering located in the Appalachia Basin area (Appalachia) of eastern Ohio, western New York, and western Pennsylvania, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of Oklahoma, Arkansas, northern and western Texas, the Texas panhandle, and southeastern Missouri. Appalachia revenues are based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are derived from the gathering and transportation of natural gas and the sale of residue gas and NGLs to purchasers at the tailgate of the processing plants.

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Revenue Recognition

Revenue in the Partnership s Appalachia segment is recognized at the time the natural gas is transported through its gathering systems. Under the terms of its natural gas gathering agreements with Atlas Energy and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas Energy and by drilling investment partnerships sponsored by Atlas Energy. The fees received for the gathering services under the Atlas Energy agreements are generally the greater of 16% of the gross sales price for natural gas produced from the wells, or $0.35 or $0.40 per thousand cubic feet (mcf), depending on the ownership of the well. Substantially all natural gas gathering revenue in the Appalachia segment is derived from these agreements. Fees for transportation services provided to independent third parties whose wells are connected to the Partnership s Appalachia gathering systems are at separately negotiated prices.

The Partnership s Mid-Continent segment revenue primarily consists of the fees earned from its transmission, 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 transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the Partnership s FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. 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 for a set fee for gathering and processing raw natural gas. The Partnership s revenue is a function of the volume of natural gas that it gathers and processes and is not directly dependent on the value of the natural gas.

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 situation, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership owns a percentage of that commodity and is directly subject to its market value.

Keep-Whole Contracts. These contracts require the Partnership, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, the Partnership bears the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that it paid for the unprocessed natural gas. However, because the natural gas received by the Elk City/Sweetwater system, which has keep-whole contracts, is generally low in liquids content and meets downstream pipeline specifications without being processed, the natural gas can be bypassed around the Elk City and Sweetwater processing plants and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of APL s keep-whole contracts is minimized.

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 transportation 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, 2007 and December 31, 2006 of $86.8 million and $20.2 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets

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) 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 9).

New Accounting Standards

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported, and disclosed on the face of the consolidated statement of income, at amounts that include the amounts attributable to both the parent and the noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 160 upon its adoption on January 1, 2009 and is currently evaluating whether SFAS No. 160 will have an impact on its financial position and results of operations.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations , however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date, be measured at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the noncontrolling interests in the acquiree, at the full amounts of their fair values. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 141(R) upon its adoption on January 1, 2009 and is currently evaluating whether SFAS No. 141(R) will have an impact on its financial position and results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 will be effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. The Partnership adopted SFAS No. 159 at January 1, 2008 and it had no material impact on its financial position or results of operations.

In December 2006, the FASB issued FASB Staff Position EITF 00-19-2, Accounting for Registration Payment Arrangements (EITF 00-19-2). EITF 00-19-2 provides guidance related to the accounting for registration payment arrangements and specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate arrangement or included as a provision of a financial instrument or arrangement, should be separately recognized and measured in accordance with SFAS No. 5, Accounting for Contingencies (SFAS No. 5). EITF 00-19-2 requires that if the transfer of consideration under a registration payment arrangement is probable and can be reasonably estimated at inception, the contingent liability under such arrangement shall be included in the allocation of proceeds from the related financing transaction using the measurement guidance in SFAS No. 5. The Partnership adopted EITF 00-19-2 on January 1, 2007 and it did not have an effect on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. This statement does not require any new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. However, in February, 2008, the FASB issued Staff Position No. 157-2, which defers the effective date of SFAS No. 157 as it pertains to fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008. The Partnership adopted SFAS No. 157 at January 1, 2008 and it had no material impact on its financial position or results of operations.

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on quantifying and evaluating the materiality of unrecorded misstatements. The SEC staff recommends that misstatements should be quantified using both a balance sheet and income statement approach and a determination be made as to whether either approach results in quantifying a misstatement which the registrant, after evaluating all relevant factors, considers material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct misstatements occurring in prior years that previously had been considered immaterial based on the appropriate use of the registrant s methodology. SAB 108 is effective for fiscal years ending on or after November 15, 2006. SAB 108 did not have an impact on the Partnership s consolidated financial position or results of operations for the year ended December 31, 2007.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

In July 2007, the Partnership sold 25.6 million common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25.6 million common units sold by the Partnership, 3.8 million were purchased by AHD for $168.8 million. The Partnership also received a capital contribution from AHD of $23.1 million in order for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from the sale to partially fund the acquisition of control of the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and a 72.8% interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (see Note 8).

The common units sold by the Partnership in the July 2007 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that the Partnership would (a) file a registration statement with the Securities and Exchange Commission for the common units by November 24, 2007 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by March 2, 2008. On November 28, 2007, the registration statement the Partnership filed with the Securities and Exchange Commission for the common units subject to the registration rights agreement was declared effective, thereby fulfilling the requirements of the registration rights agreement.

In May 2006, the Partnership sold 0.5 million common units to Wachovia Securities, which then offered the common units to public investors. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale to partially repay borrowings under its credit facility made in connection with its acquisition of the remaining 25% ownership interest in NOARK.

In November 2005, the Partnership sold 2.7 million of its common units in a public offering for gross proceeds of $113.4 million. In addition, pursuant to an option granted to the underwriters of the offering, the Partnership sold an additional 330,000 common units in December 2005 for gross proceeds of $13.9 million, resulting in aggregate total gross proceeds of $127.3 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in total net proceeds of approximately $121.0 million, after underwriting commissions and other transaction costs. The Partnership primarily utilized the net proceeds from the sale to repay a portion of the amounts due under its credit facility.

In June 2005, the Partnership sold 2.3 million common units in a public offering for total gross proceeds of $96.5 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $91.7 million, after underwriting commissions and other transaction costs. The Partnership primarily utilized the net proceeds from the sale to repay a portion of the amounts due under its credit facility.

NOTE 4 PREFERRED UNIT EQUITY OFFERING

On March 13, 2006, the Partnership entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. The Partnership also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital for $10.0 million on May 19, 2006, pursuant to the Partnership s right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date for the Partnership s common units. On April 18, 2007, the Partnership and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of the Partnership s common units as of the date of the notice of conversion. The Partnership may elect to pay cash rather than issue common units in satisfaction of a conversion request. The Partnership has the right to call the preferred units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.82. In consideration of Sunlight Capital s consent to the amendment of the preferred units, the Partnership issued $8.5 million of its 8.125% senior unsecured notes due 2015 (the Notes) (see Note 10) to Sunlight Capital. The Partnership recorded the Notes as long-term debt and a preferred unit dividend within partners capital, and has reduced net income (loss) attributable to common limited partners and the general partner by $3.8 million of this amount, which is the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on its consolidated statements of operations.

The preferred units are reflected on the Partnership s consolidated balance sheet as preferred equity within partners capital. In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the preferred units were originally recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost of $2.4

million was the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006 and was amortized in full as of March 12, 2007. As a result of the amended agreement, the Partnership recognized an imputed dividend cost of $2.5 million that will be amortized during the year commencing March 13, 2007 and is based upon the present value of the net proceeds received using the 6.5% stated yield.

Amortization of the imputed dividend cost, 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, was $2.5 million for the year ended December 31, 2007, based on the imputed dividend cost for the period commencing March 13, 2007, the date of amendment. Amortization of the imputed dividend cost was $1.9 million for the year ended December 31, 2006, based on the $2.4 million imputed cost during the initial year after the unit issuance. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet. Dividends accrued and paid on the preferred units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner.

The net proceeds from the initial issuance of the preferred units were used to fund a portion of the Partnership s capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under the Partnership s credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

NOTE 5 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, 2005 through December 31, 2007 were as follows:

Date Cash Distribution Paid	For Quarter Ended	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)
February 11, 2005	December 31, 2004	$ 0.72	$ 5,187	$ 1,280
May 13, 2005	March 31, 2005	$ 0.75	$ 5,404	$ 1,501
August 5, 2005	June 30, 2005	$ 0.77	$ 7,319	$ 2,174
November 14, 2005	September 30, 2005	$ 0.81	$ 7,711	$ 2,565
February 14, 2006	December 31, 2005	$ 0.83	$ 10,416	$ 3,638
May 15, 2006	March 31, 2006	$ 0.84	$ 10,541	$ 3,766
August 14, 2006	June 30, 2006	$ 0.85	$ 11,118	$ 4,059
November 14, 2006	September 30, 2006	$ 0.85	$ 11,118	$ 4,059
February 14, 2007	December 31, 2006	$ 0.86	$ 11,249	$ 4,193
May 15, 2007	March 31, 2007	$ 0.86	$ 11,249	$ 4,193
August 14, 2007	June 30, 2007	$ 0.87	$ 11,380	$ 4,326
November 14, 2007	September 30, 2007	$ 0.91	$ 35,205	$ 4,498

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In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems (see Note 8), AHD, which holds all of the incentive distribution rights in the Partnership, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter.

On January 28, 2008, the Partnership declared a cash distribution of $0.93 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2007. The $41.1 million distribution, including $10.2 million to the General Partner after the allocation of $5.0 million of its incentive distribution rights back to the Partnership, was paid on February 14, 2008 to unitholders of record at the close of business on February 7, 2008.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2007	December 31, 2006	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,633,454	$ 611,575	15 40
Rights of way	168,359	30,401	20 40
Buildings	8,919	3,800	40
Furniture and equipment	7,235	3,288	3 7
Other	13,307	2,081	3 10
	1,831,274	651,145	
Less accumulated depreciation	(82,613)	(44,048)	
	$ 1,748,661	$ 607,097	

In July 2007, the Partnership acquired control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). Due to the recent date of acquisition, the purchase price allocation is based upon estimated values determined by the Partnership, which are subject to adjustment and could change as it continues to evaluate this allocation. At December 31, 2007, the portion of the purchase price allocated to property, plant and equipment for this acquisition is primarily located within pipeline, processing, and compression facilities.

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK for $69.0 million in cash, including the repayment of the $39.0 million of NOARK notes at the date of acquisition (see Note 8). The Partnership acquired the initial 75% ownership interest in NOARK for approximately $179.8 million in October 2005 (see Note 8). During 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships intangible assets and goodwill based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment.

NOTE 7 OTHER ASSETS

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

	December 31, 2007	December 31, 2006
Deferred finance costs, net of accumulated amortization of $11,352 and $3,972 at December 31, 2007 and 2006, respectively	$ 18,227	$ 12,530
Security deposits	2,498	1,415
Other	156	97
	$ 20,881	$ 14,042

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 10). In July 2007, the Partnership recorded $5.0 million for accelerated amortization of deferred financing costs associated with the replacement of its previous credit facility with a new facility (see Note 10).

NOTE 8 ACQUISITIONS

Chaney Dell and Midkiff/Benedum

On July 27, 2007, the Partnership acquired control of Anadarko s 100% interest in the Chaney Dell natural gas gathering system 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 (the Anadarko Assets). The Chaney Dell System includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum System includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which the Partnership contributed $1.9 billion and Anadarko contributed the Anadarko Assets.

In connection with this acquisition, the Partnership has reached an agreement with Pioneer, which currently holds a 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer will have an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008, and up to an additional 7.4% interest beginning on June 15, 2009. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22% interest if fully exercised. The Partnership will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

The Partnership funded the purchase price in part from the private placement of $1.125 billion of its common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by AHD. AHD, which holds all of the incentive distribution rights in the Partnership, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter (see Note 5). The Partnership funded the remaining purchase price from an $830.0 million senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013 (see Note 10).

The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, Business Combinations (SFAS No. 141). The following table presents the preliminary purchase price allocation as of December 31, 2007, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in the acquisition, based on their fair values at the date of the acquisition (in thousands):

Prepaid expenses and other	$ 4,587
Property, plant and equipment	1,030,232
Intangible assets customer relationships	205,312
Goodwill	645,842
Total assets acquired	1,885,973
Accounts payable and accrued liabilities	(1,515)
Net cash paid for acquisition	$ 1,884,458

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The Partnership recorded goodwill in connection with this acquisition as a result of Chaney Dell s and Midkiff/Benedum s significant cash flow and strategic industry position. Due to the recent date of the acquisition, the purchase price allocation for the acquisition is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate this allocation. Unresolved items which could affect the final purchase price allocation include, among other things, the recoverability of state sales tax paid on the transaction, which has been included as an acquisition cost. The recovery of state sales tax paid on the transaction in future periods could reduce amounts allocated to goodwill. The results of Chaney Dell s and Midkiff/Benedum s operations are included within the Partnership s consolidated financial statements from the date of acquisition.

NOARK

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern, for a net purchase price of $65.5 million, consisting of $69.0 million of cash to the seller (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in NOARK s working capital (including cash on hand and net payables to the seller) at the date of acquisition of $3.5 million. In October 2005, the Partnership acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), all of the outstanding equity of Atlas Arkansas Pipeline, LLC, which owned the initial 75% ownership interest in NOARK, for total consideration of $179.8 million, including $16.8 million for working capital adjustments and other related transaction costs. NOARK s assets included a Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and an unregulated natural gas gathering system. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in both acquisitions, based on their fair values at the date of the respective acquisitions (in thousands):

Cash and cash equivalents	$ 16,215
Accounts receivable	11,091
Prepaid expenses	497
Property, plant and equipment	232,576
Other assets	140
Total assets acquired	260,519
Accounts payable and other liabilities	(50,689)
Net assets acquired	209,830
Less: Cash and cash equivalents acquired	(16,215)
Net cash paid for acquisitions	$ 193,615

The Partnership s ownership interests in the results of NOARK s operations associated with each acquisition are included within its consolidated financial statements from the respective dates of the acquisitions.

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Elk City

In April 2005, the Partnership acquired all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd. (Elk City), a Texas limited partnership, for $196.0 million, including related transaction costs. Elk City s principal assets included approximately 450 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma, a natural gas processing facility in Elk City, Oklahoma and a natural gas treatment facility in Prentiss, Oklahoma. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed, based on their fair values at the date of acquisition (in thousands):

Accounts receivable	$ 5,587
Other assets	497
Property, plant and equipment	104,106
Intangible assets customer contracts	12,390
Intangible assets customer relationships	17,260
Goodwill	61,136
Total assets acquired	200,976
Accounts payable and accrued liabilities	(4,970)
Net assets acquired	$ 196,006

The Partnership recorded goodwill in connection with this acquisition as a result of Elk City s significant cash flow and its strategic industry position. Elk City s results of operations are included within the Partnership s consolidated financial statements from its date of acquisition.

The following data presents pro forma revenue and net income (loss) for the Partnership for the years ended December 31, 2007 and 2006 as if the acquisitions discussed above, the equity offerings in July 2007 and May 2006 (see Note 3), the issuance of an $830.0 million term loan and a new $300.0 million senior secured credit facility and respective borrowings under these facilities (see Note 10), the April 2007 and May 2006 issuances of senior notes (see Note 10), and the May 2006 and March 2006 issuances of the cumulative convertible preferred units (see Note 4) had occurred on January 1, 2006. The following data also presents pro forma revenue and net income (loss) for the Partnership for the year ended December 31, 2005 as if the NOARK and Elk City acquisitions discussed above, the equity offerings in November 2005 and June 2005 (see Note 3), and the December 2005 issuance of senior notes (see Note 10) had occurred on January 1, 2005. The Partnership has prepared these unaudited pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed these acquisitions and financing transactions at the beginning of the periods shown below or the results that will be attained in the future (in thousands, except per unit data; unaudited):

	Years Ended December 31,		
	2007	**2006**	**2005**
Total revenue and other income (loss)	$ 990,032	$ 1,090,583	$ 469,867
Net income (loss)	(135,772)	32,498	21,148
Net income (loss) attributable to common limited partners and the general partner	(142,026)	26,244	19,275
Net income (loss) attributable to common limited partners per unit:			
Basic	$ (4.00)	$ 0.29	$ 0.77
Diluted	$ (4.00)	$ 0.29	$ 0.76

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NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these 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. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133.

The Partnership formally documents all relationships between hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity futures and derivative contracts to the forecasted transactions. The Partnership assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of the hedged production. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying commodity, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by the Partnership through the utilization of market data, will be recognized immediately within other income (loss) in its consolidated statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassifies them to natural gas and liquids revenue within natural gas and liquids revenue in its consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss) in its consolidated statements of operations as they occur.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At December 31, 2007 and 2006, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $229.5 million and $20.1 million, respectively. Of the $62.1 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at December 31, 2007, if the fair values of the instruments remain at current market values, the Partnership will reclassify $43.1 million of losses to natural gas and liquids revenue in its consolidated statements of operations over the next twelve month period as these contracts expire, and $19.0 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, the Partnership signed definitive agreements to acquire control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). In connection with certain additional agreements entered into to finance this transaction, the Partnership agreed as a condition precedent to closing that it would hedge 80% of its projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, the Partnership entered into derivative instruments to hedge 80% of the projected production of the Anadarko Assets to be acquired as required under the financing agreements. The production volume of the Anadarko Assets to be acquired was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Anadarko Assets had not yet been completed. Accordingly, the Partnership recognized the instruments as non-

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qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in its consolidated statements of operations. The Partnership recognized a non-cash loss of $18.8 million related to the change in value of derivatives entered into specifically for the Chaney Dell and Midkiff/Benedum systems from the time the derivative instruments were entered into to the date of closing of the acquisition during the year ended December 31, 2007. Upon closing of the acquisition in July 2007, the production volume of the Anadarko Assets acquired was considered probable forecasted production under SFAS No. 133. The Partnership designated many of these instruments as cash flow hedges and evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

In connection with the Chaney Dell and Midkiff/Benedum acquisition, the Partnership reached an agreement with Pioneer which grants Pioneer an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system beginning on June 15, 2008 and an additional 7.4% interest beginning on June 15, 2009 (see Note 8). At December 31, 2007, the Partnership has received no indication that Pioneer will exercise either of its options under the agreement. If Pioneer does exercise either of these options, the Partnership will discontinue hedge accounting for the derivative instruments covering the portion of the forecasted production of the Midkiff/Benedum system sold to Pioneer and will evaluate these derivative instruments to determine if they can be documented to match other forecasted production the Partnership may have.

During December 2007, the Partnership discontinued hedge accounting for crude oil derivative instruments covering certain forecasted condensate production for 2008 and other future periods, and then documented these derivative instruments to match certain forecasted NGL production for the respective periods. The discontinuation of hedge accounting for these instruments with regard to the Partnership s condensate production resulted in a $12.6 million non-cash derivative loss recognized within other income (loss) in its consolidated statements of operations and a corresponding decrease in accumulated other comprehensive loss in partners capital in its consolidated balance sheet.

The following table summarizes the Partnership s derivative activity for the periods indicated (amounts in thousands):

	Year ended December 31,		
	2007	**2006**	**2005**
Loss from cash settlement of qualifying hedge instruments(1)	$ (49,393)	$ (13,945)	$ (11,125)
Gain/(loss) from change in market value of non-qualifying derivatives(2)	(153,363)	4,206	
Gain/(loss) from de-designation of cash flow derivatives(2)	(12,611)		
Gain/(loss) from change in market value of ineffective portion of qualifying derivatives(2)	(3,450)	1,520	1,625
Loss from cash settlement of non-qualifying derivatives(2)	(10,158)		

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within other income (loss) on the Partnership s consolidated statements of operations.

A portion of the Partnership s future natural gas, NGL and condensate sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to natural gas and liquids revenue within the Partnership s consolidated statements of operations.

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As of December 31, 2007, we had the following NGLs, natural gas, and crude oil volumes hedged, including derivatives that do not qualify for hedge accounting:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[(1)] (in thousands)
2008	61,362,000	$ 0.706	$ (29,435)
2009	8,568,000	0.746	(4,189)
			$ (33,624)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)[(2)] (in thousands)	Option Type
2008	4,173,600	279,347,544	$ 60.00	$ 852	Puts purchased
2008	4,173,600	279,347,544	79.23	(55,674)	Calls sold
2009	5,184,000	354,533,760	60.00	5,216	Puts purchased
2009	5,184,000	354,533,760	78.88	(64,031)	Calls sold
2010	3,127,500	213,088,050	61.08	5,638	Puts purchased
2010	3,127,500	213,088,050	81.09	(35,442)	Calls sold
2011	606,000	34,869,240	70.59	2,681	Puts purchased
2011	606,000	34,869,240	95.56	(3,924)	Calls sold
2012	450,000	25,893,000	70.80	2,187	Puts purchased
2012	450,000	25,893,000	97.10	(2,922)	Calls sold
				$ (145,419)	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu)[(3)]	Average Fixed Price (per mmbtu) [(3)]	Fair Value Asset/(Liability)[(2)] (in thousands)
2008	5,484,000	$ 8.795	$ 5,397
2009	5,724,000	8.611	538
2010	4,560,000	8.526	(351)
2011	2,160,000	8.270	(607)
2012	1,560,000	8.250	(331)
			$ 4,646

Natural Gas Basis Sales

Production Period Ended December 31,	**Volumes (mmbtu)[3]**	**Average Fixed Price (per mmbtu)[3]**	**Fair Value Asset/(Liability)[2] (in thousands)**
2008	5,484,000	$ (0.727)	$ 187
2009	5,724,000	(0.558)	828
2010	4,560,000	(0.622)	221
2011	2,160,000	(0.664)	(32)
2012	1,560,000	(0.601)	47
			$ 1,251

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Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Asset/(Liability)(2) (in thousands)
2008	16,260,000	$ 8.978(4)	$ (18,575)
2009	15,564,000	8.680	(2,542)
2010	8,940,000	8.580	464
2011	2,160,000	8.270	607
2012	1,560,000	8.250	331
			$ (19,715)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Liability(2) (in thousands)
2008	16,260,000	$ (1.114)	$ (194)
2009	15,564,000	(0.654)	(6,152)
2010	8,940,000	(0.600)	(2,337)
2011	2,160,000	(0.700)	(89)
2012	1,560,000	(0.610)	(64)
			$ (8,836)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(2) (in thousands)
2008	65,400	$ 59.424	$ (2,234)
2009	33,000	62.700	(842)
			$ (3,076)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)(2) (in thousands)	Option Type
2008	262,800	$ 60.000	$ (42)	Puts purchased
2008	262,800	78.174	(11,149)	Calls sold
2009	306,000	60.000	807	Puts purchased
2009	306,000	80.017	(9,072)	Calls sold

2010	234,000	61.795		835	Puts purchased
2010	234,000	83.027		(5,283)	Calls sold
2011	30,000	60.000		272	Puts purchased
2011	30,000	74.500		(724)	Calls sold
2012	30,000	60.000		195	Puts purchased
2012	30,000	73.900		(579)	Calls sold
			$	(24,740)	
		Total net liability	$	(229,513)	

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[(1)] Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

[(2)] Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

[(3)] Mmbtu represents million British Thermal Units.

[(4)] Includes the Partnership s premium received from its sale of an option for it to sell 936,000 mmbtu of natural gas at an average price of $15.50 per mmbtu for the year ended December 31, 2008.

NOTE 10 DEBT

Total debt consists of the following (in thousands):

	December 31, 2007	December 31, 2006
Revolving credit facility	$ 105,000	$ 38,000
Term loan	830,000	
Senior notes	294,392	285,977
Other debt	34	106
Total debt	1,229,426	324,083
Less current maturities	(34)	(71)
Total long-term debt	$ 1,229,392	$ 324,012

Term Loan and Credit Facility

In connection with the Partnership s July 27, 2007 acquisition of control of the Chaney Dell and Midkiff/Benedum systems (see Note 8), it entered into a new credit facility, comprised of an $830.0 senior secured term loan (term loan) which matures in July 2014 and a $300.0 million senior secured revolving credit facility which matures in July 2013. The Partnership borrowed $830.0 million under the term loan and $15.0 million under the revolving credit facility to finance a portion of the acquisition purchase price and to repay indebtedness under its prior revolving credit facility. Borrowings under the credit facility bear interest, at the Partnership s option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2007 was 7.2%, and the weighted average interest rate on the outstanding term loan borrowings at December 31, 2007 was 7.6%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $9.1 million was outstanding at December 31, 2007. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet. 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 the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of its 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 in compliance with these covenants as of December 31, 2007. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt or equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with the new credit facility, the Partnership agreed to remit an underwriting fee to the lead underwriting bank of the credit facility of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. In January 2008, the Partnership and the underwriting bank agreed to extend the agreement through June 30, 2008.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.5 to 1.0, increasing to 2.75 to 1.0 commencing September 30, 2008. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of December 31, 2007, the Partnership s ratio of funded debt to EBITDA was 4.4 to 1.0 and its interest coverage ratio was 3.1 to 1.0.

The Partnership is 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.

Senior Notes

At December 31, 2007, the Partnership has $293.5 million of 10-year, 8.125% senior unsecured notes due 2015 (Senior Notes) outstanding, net of unamortized premium received of $0.9 million. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, the Partnership may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes 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. On April 18, 2007, the Partnership issued Sunlight Capital $8.5 million of its Senior Notes in consideration of its consent to the amendment of the Partnership s preferred units agreement (see Note 4).

The indenture governing the Senior Notes contains covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of December 31, 2007.

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

Years Ended December 31:	
2008	$ 34
2009	
2010	
2011	
2012	
Thereafter	1,229,392
	$ 1,229,426

93

Cash payments for interest related to debt were $57.2 million, $25.5 million, and $9.2 million for the years ended December 31, 2007, 2006 and 2005, respectively.

NOTE 11 - COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space. Total rental expense for the years ended December 31, 2007, 2006 and 2005 was $5.6 million, $4.0 million, and $2.0 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2007 is as follows (in thousands):

Years Ended December 31:	
2008	$ 4,120
2009	1,732
2010	1,403
2011	1,181
2012	812
Thereafter	109
	$ 9,357

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

As of December 31, 2007, the Partnership is committed to expend approximately $168.4 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

NOTE 12 FINANCIAL INSTRUMENTS AND CONCENTRATIONS OF CREDIT RISK

The estimated fair value of financial instruments has been determined based upon the Partnership s 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 the consolidated balance sheets are financial instruments. 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 long-term debt at December 31, 2007 and 2006, which consists principally of the Term Loan, the Senior Notes, and borrowings under the Credit Facility, was $1,225.6 million and $330.9 million, respectively, compared with the carrying amount of $1,229.4 million and $324.0 million, respectively. The Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

The Partnership sells natural gas and NGLs under contract to various purchasers in the normal course of business. For the year ended December 31, 2007, the Mid-Continent segment had one customer that individually accounted for approximately 53% of the Partnership s consolidated total revenues, excluding the impact of non-cash derivative items; three customers that individually accounted for approximately 37%, 19% and 10% of the Partnership s consolidated total revenues, excluding the impact of non-cash derivative items, for the year ended December 31, 2006 and three customers that individually accounted for approximately 33%, 15% and 11% of the Partnership s consolidated total revenues, excluding the impact of non-cash derivative items, for the year ended

December 31, 2005. Additionally, the Mid-Continent segment had two customers that accounted for approximately 26% and 11% and one customer that accounted for approximately 16% of the Partnership s consolidated accounts receivable at December 31, 2007 and 2006, respectively. Substantially all of the Appalachian segment s revenues are derived from a master gas gathering agreement with Atlas Energy.

The Partnership has certain producers which supply a majority of the natural gas to its Mid-Continent gathering and transportation 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, 2007, the Partnership and its subsidiaries had $57.6 million in deposits at banks, of which $56.8 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 13 STOCK COMPENSATION

Long-Term Incentive Plan

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through December 31, 2007.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant 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. A unit option entitles the grantee to purchase the Partnership s common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through December 31, 2007, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. 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 LTIP. Of the units outstanding under the LTIP at December 31, 2007, 56,481 units will vest within the following twelve months. All units outstanding under the LTIP at December 31, 2007 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs were $0.6 million, $0.4 million and $0.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. These amounts were recorded as reductions of Partners Capital on the consolidated balance sheet.

The Partnership follows the provisions of SFAS No. 123(R). Generally, the approach to accounting in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

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

	Years Ended December 31,		
	2007	2006	2005
Outstanding, beginning of year	159,067	110,128	58,329
Granted[(1)]	25,095	82,091	67,399
Matured	(51,166)	(31,152)	(14,581)
Forfeited	(3,250)	(2,000)	(1,019)
Outstanding, end of year	129,746	159,067	110,128
Non-cash compensation expense recognized (in thousands)	$ 2,936	$ 2,030	$ 2,201

(1) The weighted average price for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, was $50.09, $45.45 and $48.59 for awards granted for the years ended December 31, 2007, 2006 and 2005, respectively.

At December 31, 2007, 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.

Incentive Compensation Agreements

The Partnership has incentive compensation agreements which have granted awards to certain key employees retained from previously consummated acquisitions. These individuals are 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. Of the total common units to be issued under the incentive compensation agreements, 58,822 were issued during the year ended December 31, 2007. The remaining common units to be issued under the incentive compensation agreements will be determined based upon the financial performance of certain Partnership assets for the year ended December 31, 2008. The incentive compensation agreements also dictates that no individual covered under the agreements shall receive an amount of common units in excess of one percent of the outstanding common units of the Partnership at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units of the Partnership shall be paid in cash.

The Partnership recognized compensation expense of $33.4 million, $4.3 million, and $2.5 million for the years ended December 31, 2007, 2006 and 2005, respectively, related to the vesting of awards under these incentive compensation agreements. The increase in non-cash compensation expense was due to an increase in common unit awards estimated by management to be issued under incentive compensation agreements to certain key employees as a result of the acquisition of the Chaney Dell and Midkiff/Benedum systems. The ultimate number of common units estimated to be issued under the incentive compensation agreements will be determined by the financial performance of certain Partnership assets for the year ended December 31, 2008. The vesting period for such awards concluded on September 30, 2007 and all compensation expense related to the awards was recorded as of that date. Management anticipates that adjustments will be recorded in future periods with respect to the awards under the incentive compensation agreements based upon the actual financial performance of the assets in future periods in comparison to their estimated performance. Based upon management s estimate of the probable outcome of the performance targets at December 31, 2007, 948,847 common unit awards are ultimately expected to be issued under these agreements, which represents the amount of common units expected to be issued under the incentive compensation agreements. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method.

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NOTE 14 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 Atlas America. 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 their 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 Atlas America based on the number of its employees who devote their time to activities on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses 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 $5.9 million, $2.3 million and $1.8 million for the years ended December 31, 2007, 2006 and 2005, respectively, for compensation and benefits related to their employees. For the years ended December 31, 2007, 2006 and 2005, direct reimbursements were $26.4 million, $28.6 million and $24.8 million, respectively, including certain costs that have been capitalized by the Partnership. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

Under an agreement between the Partnership and Atlas Energy, Atlas Energy must construct up to 2,500 feet of sales lines from its existing wells in the Appalachian region to a point of connection to the Partnership s gathering systems. The Partnership must, at its own cost, extend its system to connect to any such lines within 1,000 feet of its gathering systems. With respect to wells to be drilled by Atlas Energy that will be more than 3,500 feet from the Partnership s gathering systems, the Partnership has various options to connect those wells to its gathering systems at its own cost.

NOTE 15 SEGMENT INFORMATION

The Partnership has two reportable segments: natural gas transmission and gathering located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York and western Pennsylvania, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle, Arkansas, and southeastern Missouri. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and transport of natural gas. These reportable segments reflect the way the Partnership manages its operations.

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

	Years Ended December 31, 2007	2006	2005
Mid-Continent			
Revenue:			
Natural gas and liquids	$ 759,553	$ 391,356	$ 338,672
Transportation, compression and other fees	48,041	30,653	5,880
Other income (loss)	(174,438)	11,804	2,138
Total revenues and other income (loss)	633,156	433,813	346,690
Costs and expenses:			
Natural gas and liquids	586,677	334,299	288,180
Plant operating	34,667	15,722	10,557
Transportation and compression	7,249	5,807	952
General and administrative	48,332	15,036	7,375
Depreciation and amortization	46,327	19,322	11,307
Minority interests	3,940	118	1,083
Total costs and expenses	727,192	390,304	319,454
Segment profit (loss)	$ (94,036)	$ 43,509	$ 27,236
Appalachia			
Revenue:			
Natural gas and liquids	$ 1,565	$	$
Transportation, compression and other fees affiliates	33,169	30,189	24,346
Transportation, compression and other fees third parties	575	82	83
Other income	335	608	381
Total revenues and other income	35,644	30,879	24,810
Costs and expenses:			
Natural gas and liquids	847		
Transportation and compression	6,235	4,946	3,101
General and administrative	6,327	3,767	3,117
Depreciation and amortization	4,655	3,672	2,647
Total costs and expenses	18,064	12,385	8,865
Segment profit	$ 17,580	$ 18,494	$ 15,945
Reconciliation of segment profit to net income (loss):			
Segment profit (loss):			
Mid-Continent	$ (94,036)	$ 43,509	$ 27,236
Appalachia	17,580	18,494	15,945
Total segment profit (loss)	(76,456)	62,003	43,181
Corporate general and administrative expenses	(6,327)	(3,766)	(3,116)
Interest expense	(61,526)	(24,572)	(14,175)
Other			(138)

Net income (loss)	$ (144,309)	$ 33,665	$ 25,752
Capital Expenditures:			
Mid-Continent	$ 133,270	$ 65,416	$ 35,263
Appalachia	19,620	18,415	17,235
	$ 152,890	$ 83,831	$ 52,498

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	December 31, 2007	December 31, 2006
Balance sheet		
Total assets:		
Mid-Continent	$ 2,813,049	$ 730,791
Appalachia	43,860	42,448
Corporate other	20,705	13,645
	$ 2,877,614	$ 786,884
Goodwill:		
Mid-Continent	$ 706,978	$ 61,136
Appalachia	2,305	2,305
	$ 709,283	$ 63,441

The following tables summarize the Partnership s total revenues by product or service for the periods indicated (in thousands):

	Years Ended December 31, 2007	2006	2005
Natural gas and liquids:			
Natural gas	$ 264,438	$ 196,182	$ 198,972
NGLs	434,773	169,840	126,498
Condensate	27,269	6,678	5,417
Other (1)	34,638	18,656	7,785
Total	$ 761,118	$ 391,356	$ 338,672
Transportation, compression, and other fees:			
Affiliates	$ 33,169	$ 30,189	$ 24,346
Third parties	48,616	30,735	5,963
Total	$ 81,785	$ 60,924	$ 30,309

(1) Includes treatment, processing, and other revenue associated with the products noted.

NOTE 16 - QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter(1)	Third Quarter(1)	Second Quarter(1)	First Quarter(1)
	(in thousands, except per unit data)			
Year ended December 31, 2007:				
Revenue and other income (loss)	$ 213,548	$ 242,300	$ 95,415	$ 117,537
Costs and expenses	315,002	266,798	116,231	115,078
Net income (loss)	(101,454)	(24,498)	(20,816)	2,459
Basic net loss per common limited partner unit	$ (2.69)	$ (0.90)	$ (2.20)	$ (0.14)
Diluted net loss per common limited partner unit	$ (2.69)	$ (0.90)	$ (2.20)	$ (0.14)

(1) For the fourth, third, second, and first quarters of the year ended December 31, 2007, approximately 962,000, 619,000, 271,000, and 245,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the fourth, third, second, and first quarters of the year ended December 31, 2007, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1,000 par value 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.

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	Fourth Quarter[1]	Third Quarter[2]	Second Quarter	First Quarter
	(in thousands, except per unit data)			
Year ended December 31, 2006:				
Revenue and other income	$ 116,835	$ 120,546	$ 109,501	$ 117,810
Costs and expenses	109,363	113,545	99,808	108,311
Net income	7,472	7,001	9,693	9,499
Basic net income per common limited partner unit	$ 0.22	$ 0.20	$ 0.41	$ 0.46
Diluted net income per common limited partner unit[3]	$ 0.22	$ 0.19	$ 0.41	$ 0.46

(1) Includes the Partnership s $2.9 million gain from the settlement of an insurance claim pertaining to fire damage to a compressor station within the Velma region of its Mid-Continent segment.

(2) Includes the Partnership s $2.7 million gain from the sale of certain gathering pipelines within the Velma system.

(3) For the fourth, third and second quarters of the year ended December 31, 2006, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1,000 par value cumulative convertible preferred limited partner units were excluded from the computation of diluted net income attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

NOTE 17 SUBSEQUENT EVENT

During January 2008, the Partnership entered into interest rate derivative contracts having an aggregate notional principal amount of $200.0 million. Under the terms of this agreement, the Partnership will pay 2.88%, plus the applicable margin as defined under the terms of its credit facility, and will receive LIBOR plus the applicable margin, on the notional principal amount of $200.0 million. This hedge effectively converts $200.0 million of the Partnership s floating rate debt under the credit facility to fixed-rate debt. The interest rate swap agreement begins on January 31, 2008 and expires on January 31, 2010.

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, 2007, our disclosure controls and procedures were effective.

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.

In conducting management s evaluation of the effectiveness of its internal control over financial reporting, management has excluded, due to their size and complexity, the operations of the Partnership s newly acquired Chaney Dell and Midkiff/Benedum systems, which were acquired in July 2007, from its December 31, 2007 Sarbanes-Oxley 404 review. In connection with this acquisition, the Partnership entered into a transition services agreement with the former owner and, as a result, did not begin to perform substantially all accounting control functions for these systems until November 1, 2007. The Chaney Dell and Midkiff/Benedum systems constituted 68% of the Partnership s total assets as of December 31, 2007, 41% of its total revenues and 33% of its net loss for the year ended December 31, 2007 (see Note 8 to the consolidated financial statements which contain further discussion of these acquisitions). We believe that management had sufficient cause to exclude this acquisition in its evaluation of the effectiveness of its internal control over financial reporting based on the size, complexity, and timing of the acquisition.

Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective as of December 31, 2007. Grant Thornton LLP, an independent registered public accounting firm and auditors of our consolidated financial statements, has issued an attestation report on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2007, which is included herein.

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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 (Partnership) (a Delaware limited partnership) internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Managements Report on Internal Control over Financial Reporting . Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

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

In conducting management s evaluation of the effectiveness of its internal control over financial reporting, management has excluded, due to its size and complexity, the Partnership s subsidiaries Atlas Pipeline Mid-Continent WestOk, LLC. (Chaney Dell) and Atlas Pipeline Mid-Continent WestTex, LLC. (Midkiff/Benedum), which were recently acquired in July 2007. The Chaney Dell and Midkiff/Benedum systems constituted 68% of the Partnership s total assets as of December 31, 2007, 41% of its total revenues and 33% of its net loss for the year ended December 31, 2007. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of Chaney Dell and Midkiff/Benedum.

A partnership 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 partnership 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 partnership; (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 partnership are being made only in accordance with authorizations of management and directors of the partnership; (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or dispositions of the partnership s assets that could have a material effect on the financial statements.

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by COSO.

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We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2007 and our report dated February 27, 2008 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 27, 2008

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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 the managing board meet in executive session regularly without management. The managing board member who will preside 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 both 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. Any matters approved by the conflicts committee are conclusively judged to be fair and reasonable to us, approved by all our partners and not a breach by our general partner or its managing board of any duties they may owe us or the unitholders. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operation. Rather, Atlas America personnel manage and operate our business. Officers of our general partner may spend a substantial amount of time managing the business and affairs of Atlas America and its affiliates and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Managing Board Members and Executive Officers of Our General Partner

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

Name	Age	Position with general partner	Year in which service began
Edward E. Cohen	69	Chairman of the Managing Board and Chief Executive Officer	1999
Jonathan Z. Cohen	37	Vice Chairman of the Managing Board	1999
Michael L. Staines	58	President, Chief Operating Officer and Managing Board Member	1999
Matthew A. Jones	46	Chief Financial Officer	2005
Robert R. Firth	53	President & Chief Executive Officer of Atlas Pipeline Mid-Continent, LLC	2004
Tony C. Banks	53	Managing Board Member	1999
Curtis D. Clifford	65	Managing Board Member	2004
Gayle P.W. Jackson	61	Managing Board Member	2005
Martin Rudolph	61	Managing Board Member	2005

Edward E. Cohen has been the Chairman of the managing board and Chief Executive Officer of our general partner since its formation in 1999. Mr. Cohen has been the Chairman of the Board and Chief Executive Officer of Atlas Holdings GP, the general partner of Atlas Pipeline Holdings, since its formation in January 2006. Mr. Cohen also has been the Chairman of the Board and Chief Executive Officer of Atlas America since its organization in 2000. Mr. Cohen has been the Chairman of the Board and Chief Executive Officer of Atlas Energy and its manager, Atlas Energy Management, Inc.; since their formation in June 2006. 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; 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.

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 Vice Chairman of the Board of Atlas Holdings GP since its formation in January 2006. Mr. Cohen also has been the Vice Chairman of the Board of Atlas America since its organization in 2000. Mr. Cohen has been Vice Chairman of the Board of Atlas Energy and Atlas Energy Management since their formation in June 2006. 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, 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.

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Michael L. Staines has been our President and Chief Operating Officer since 2000. Mr. Staines has been an Executive Vice President of Atlas America since its formation in 2000. 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 Ohio Oil and Gas Association, the Independent Oil and Gas Association of New York and the Independent Petroleum Association of America.

Matthew A. Jones has been Chief Financial Officer of our general partner and the Chief Financial Officer of Atlas America since March 2005. Mr. Jones has been the Chief Financial Officer of Atlas Holdings GP since January 2006 and a director since February 2006. He has been the Chief Financial Officer and a director of Atlas Energy and Atlas Energy Management since their formation. From 1996 to 2005, Mr. Jones worked in the Investment Banking Group at Friedman Billings Ramsey, concluding as Managing Director. Mr. Jones worked in Friedman Billings Ramsey s Energy Investment Banking Group from 1999 to 2005, and in Friedman Billings Ramsey s Specialty Finance and Real Estate Group from 1996 to 1999. Mr. Jones is a Chartered Financial Analyst.

Robert R. Firth has been the President and Chief Executive Officer of Atlas Pipeline Mid-Continent LLC since July 2004. Mr. Firth has been a director of Atlas Pipeline Holdings GP since February 2006 and has been the President and Chief Operating Officer of Atlas Pipeline Holdings GP since January 2006. Before joining Atlas Pipeline Mid-Continent, Mr. Firth had been President and Chief Executive Officer of Spectrum, its predecessor, since 2002. From September 2001 to June 2002, Mr. Firth was Vice President of Business Development for CMS Field Services. From July 2000 to September 2001, Mr. Firth helped to form ScissorTail Energy through the acquisition of Octagon Resources, where he served as Vice President of Operations and Commercial Services. In addition to the positions listed above, Mr. Firth has held positions with Northern Natural Gas, Panda Resources and Transok in his approximately 30 years in the midstream energy sector.

Tony C. Banks has been Vice President of Business Development, Performance & Management for FirstEnergy Corporation, a public utility, since March 2007. Mr. Banks joined FirstEnergy Solutions, Inc., a subsidiary of FirstEnergy Corporation, in August 2004 as Director of Marketing and in August 2005 became Vice President of Sales & Marketing. From December 2005 to February 2007, Mr. Banks was Vice President of Business Development for FirstEnergy. 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 America. In addition, Mr. Banks served as President of our general partner during 2000. He was Chief Executive Officer and President of Atlas America from 1998 through 2000. Since October 2000, he has served on the board of directors of TRM Corporation, a provider of ATM services, and is a member of the audit committee.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Mr. Clifford has 41 years experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and consulting. Currently he works for UtiliTech, Inc., utility and telecommunications specialists in Wyomissing, PA where he advises and assists commercial and industrial gas consumers nationwide with procurement activities and utility rate options. 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 registered professional engineer in Pennsylvania.

Gayle P.W. Jackson has been President 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. 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 Cleantech Private Equity, a London-based private equity buyout fund manager that invests in clean technology companies.

Martin Rudolph has been the Trustee of the AHP Settlement Trust, a $4 billion 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 a Managing Partner of Rudolph, Palitz LLC, which was merged with RSM McGladrey. Mr. Rudolph is a certified public accountant.

Other Significant Employees

David D. Hall, 50, has been the Executive Vice President and Chief Financial Officer of Atlas Pipeline Mid-Continent LLC since July 2004. Before that, he had been the Executive Vice President and Chief Financial Officer of Spectrum Since 2002. From 2000 to 2002, Mr. Hall served as a senior business analyst at ScissorTail Energy. Mr. Hall has more than 25 years experience as a financial executive in the energy industry. Mr. Hall is a Certified Public Accountant.

Daniel C. Herz, 31, has been our Senior Vice President of Corporate Development since August 2007. He has also been the Senior Vice President of Corporate Development of Atlas America, Atlas Pipeline Holdings GP and Atlas Energy Resources, LLC since August 2007. Before that, he was Vice President of Corporate Development of Atlas America and Atlas Pipeline Partners GP from December 2004 and of Atlas Pipeline Holdings GP from its formation in January 2006. Mr. Herz joined Atlas America and Atlas Pipeline Partners GP in January 2004. He was an Associate Investment Banker with Banc of America Securities from 2002 to 2003 and an Analyst in the Energy Group from 1999 to 2002.

Sean P. McGrath, 36, has been the Chief Accounting Officer of our general partner since May 2005. Mr. McGrath has been the Chief Accounting Officer of Atlas Holdings GP since January 2006. Mr. McGrath was the Controller of Sunoco Logistics Partners L.P., a publicly-traded partnership that transports, terminals and stores refined products and crude oil, from 2002 to 2005. Mr. McGrath is a Certified Public Accountant.

Lisa Washington, 40, has been the Chief Legal Officer, Vice President and Secretary of our general partner since November 2005. Ms. Washington has been the Chief Legal Officer and Secretary of Atlas Holdings GP since January 2006. Ms. Washington also has been the Vice President, Chief Legal Officer and Secretary of Atlas America since November 2005. She is also the Chief Legal Officer and Secretary of Atlas Energy and Atlas Energy Management, positions she has held since their formation in 2006. From 1999 to 2005, Ms. Washington was an attorney in the business department of the law firm of Blank Rome LLP.

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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 2007, except that Messrs. E. Cohen, J. Cohen, Jones and Staines each inadvertently filed one Form 4 late.

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 Atlas America, 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 $5.9 million for compensation and benefits related to our executive officers and $26.4 million for direct reimbursements, including certain costs that have been capitalized by us, during 2007.

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, Mr. Banks and Ms. Jackson, 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 has a compensation committee. Compensation of the personnel of Atlas America and its affiliates who provide us with services is set by Atlas America 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 America 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.

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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 code of business conduct and ethics will be posted, on our website at www.atlaspipelinepartners.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We are required to provide information regarding the compensation program in place as of December 31, 2007, for our CEO, CFO and the three other most highly-compensated executive officers. In this report, we refer to our 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.

Through the end of 2007, the compensation committee of Atlas America, our parent, has been responsible for formulating and presenting recommendations to its Board of Directors and our board with respect to the compensation of our named executive officers. We do not directly compensate our named executive officers. Rather, Atlas America allocates the compensation of the executive officers between activities on behalf of us and activities on behalf of itself and its affiliates based upon an estimate of the time spent by such persons on activities for us and for Atlas America and its affiliates. We reimburse Atlas America for the compensation allocated to us. The compensation allocation was $5.9 million for the year ended December 31, 2007. The compensation committee is also responsible for administering our employee benefit plans, including incentive plans. The compensation committee is comprised solely of independent directors of Atlas America.

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.

The compensation awarded to our NEOs for fiscal 2007 specifically was intended:

- To encourage and reward strong performance; and
- To motivate our NEOs by providing them with a meaningful equity stake in our company and our publicly-traded subsidiaries, as appropriate.

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 compensation committee makes recommendations to the Atlas America board on compensation amounts during the month after the close of its (and our) fiscal year. In the case of base salaries, it recommends the amounts to be paid for that year. In the case of annual bonus and long-term incentive compensation, the committee recommends the amount of awards based on the then concluded fiscal year. We typically pay cash awards and issue equity awards in February of the following fiscal year. The compensation committee has the discretion to recommend the issuance of equity awards at other times during the fiscal year. In addition, some of our NEOs who also perform services for Atlas America and its other publicly-traded subsidiaries, Atlas Energy Resources and Atlas Pipeline Holdings, may receive stock-based awards from these subsidiaries, each of which have delegated compensation decisions to the compensation committee since neither we, nor the other subsidiaries, have employees.

Each year, Atlas America s (and our) Chief Executive Officer provides the compensation committee with key elements of Atlas America s performance and the NEOs performance as well as recommendations to assist it in determining compensation levels. The compensation committee focuses on Atlas America s equity performance, market capitalization, corporate developments, business performance (including production of energy and replacement of reserves) and financial position in recommending the compensation for those NEOs who provided services to both Atlas America and to us.

In June 2006, the compensation committee retained Mercer Human Resource Consulting to analyze and review the competitiveness and appropriateness of all elements of the compensation paid by Atlas America to its executive officers, including our NEOs, individually and as a group, for fiscal 2006. The purpose of retaining Mercer was to determine whether Atlas America s compensation practices were within the norm for companies of similar size and focus. Because of the importance to Atlas America or Atlas Energy s direct-placement energy investment programs and Atlas America s creation of new initiatives entities, Mercer looked not only to the energy industry in evaluating our compensation levels but also to the financial services and alternative asset industries. Mercer s analysis established that Atlas America s fiscal 2006 compensation amounts fell between the median and the 75^{th} percentile of the peer group it used, which the compensation committee found acceptable in the context of its evaluation of the performance of the NEOs.

Ultimately, the decisions regarding executive compensation are made by the compensation committee after extensive discussion regarding appropriate compensation and are approved by the Atlas America board of directors.

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 base salary plus cash bonus. 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 Atlas America and us as measured by the elements of corporate performance mentioned above. Base salaries are not intended to compensate individuals for extraordinary performance or for above average company performance.

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Annual Incentives

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

Performance-Based Bonuses The Atlas America 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 Atlas America s fiscal year. Awards under the Senior Executive Plan are paid in cash. Notwithstanding the existence of the Senior Executive Plan, the compensation committee believes that stockholder interests are 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 reserves the right to approve compensation that is not fully deductible.

In February 2007, the compensation committee set the performance goals for the Atlas America s executive offers, some of whom are also our NEOs. Specifically, the committee decided that if Atlas America s 2007 net income, which was defined as net income before income taxes and compensatory bonuses paid, exceeded $18,000,000, a bonus pool equal to 15% of the 2007 net income would be established, from which bonus awards would be made. Pursuant to the terms of the Senior Executive Plan, in determining whether and to what extent the performance target was achieved, the compensation committee relies on information contained in the Atlas America s audited financial statements and other objectively determinable information. If the performance target was not achieved, no annual incentives would be awarded. Pursuant to the terms of the Senior Executive Plan, the compensation committee has the discretion to recommend the reduction, but not the increase, of the annual incentive awards.

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 stockholders interests. To support this objective, we provide our executives with various means to become significant stockholders, including our long-term incentive programs. These awards are usually a combination of stock options, restricted units and phantom units which vest over four years to support long-term retention of executives and reinforce our longer-term goals. Our NEOs are eligible to receive awards under our Long-Term Incentive Plan, which we refer to as our Plan, the Atlas America Stock Incentive Plan, which we refer to as the Atlas Plan, the Atlas Energy Resources Long-Term Incentive Plan, which we refer to as the ATN Plan, and the Atlas Pipeline Holdings Long-Term Incentive Plan, which we refer to as the AHD Plan, as appropriate.

Grants under our Plan: The compensation committee may recommend grants of equity awards in the form of options and/or phantom units. In May 2007, our Plan was amended to meet the deductibility requirements of Section 162(m) when the awards are granted pursuant to pre-established performance goals.

Options Options have a ten-year term and, in general, vest 25% on each anniversary of the grant date.

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Phantom Units A phantom unit is a notional unit which, upon vesting, converts into a common unit in our company. Phantom units may be granted with or without tandem distribution equivalent rights, which we refer to as DERs. In general, grants of our phantom units vest 25% on each anniversary of the grant date.

Grants under Other Plans: As described above, our NEOs who perform services for us and one or more of Atlas America s publicly-traded subsidiaries may receive stock-based awards under the Atlas Plan, the ATN Plan or the AHD Plan.

Supplemental Benefits, Deferred Compensation and Perquisites

We do not emphasize supplemental benefits for executives other than Mr. E. Cohen, and perquisites are discouraged. None of our NEOs have deferred any portion of their compensation.

Determination of 2007 Compensation Amounts

As described above, after the end of our 2007 fiscal year, the compensation committee set the base salaries of the Atlas America executives for the 2008 fiscal year and recommended incentive awards based on the prior year s performance. In carrying out its function, the compensation committee acted in consultation with Mercer.

In determining the actual amounts to be paid to the Atlas America executives, the compensation committee looked to both the individual s performance as well as to the overall performance of our company and our publicly-held subsidiaries during fiscal 2007. As described above, Atlas America allocates the cash compensation for our NEOs to us based upon an estimate of the time spent by such persons on activities for us and for Atlas America and its affiliates.

Base Salary. Consistent with its preference for having a significant portion of our NEOs overall compensation package be incentive compensation, the compensation committee decided to recommend that base salaries for 2008 be maintained at the same levels as 2007.

Annual Incentives.

Performance-Based Bonuses. The compensation committee reviewed Atlas America s financial statements and determined that the 2007 net income exceeded the pre-determined minimum threshold. It accordingly recommended for approval awards under the Senior Executive Plan. The amount of these awards that were allocated to us were as follows: Edward E. Cohen, $2,250,000; Jonathan Z. Cohen, $1,434,783; Matthew A. Jones, $900,000; and Robert R. Firth, $50,000.

Discretionary Bonuses. No discretionary bonuses were recommended by the compensation committee.

Long-Term Incentives. Additionally, the compensation committee recognized the importance of a long-term incentive component as a part of the 2007 compensation. The compensation committee recommended the award of Atlas America stock options as follows: Mr. E. Cohen 200,000 options; Mr. J. Cohen 160,000 options; and Mr. M. Jones 80,000 options. (These awards are not reflected in the Summary Compensation Table because we did not recognize expense for them in fiscal 2007). The compensation committee determined that it would not recommend that awards be made to our NEOs under our Plan, the ATN Plan or the AHD Plan because it felt that previous awards were adequate.

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The following table sets forth the compensation allocation for fiscal year 2007 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 Atlas Plan.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	Option Awards ($) (2)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Edward E. Cohen, Chairman of the Board and Chief Executive Officer of Atlas Pipeline GP	2007	$ 405,000		$ 1,254,901	$ 509,167	$ 2,250,000	$ 253,212(3)	$ 4,672,280
	2006	$ 180,000	$ 360,000	$ 674,625	$ 84,861		$ 32,300	$ 1,331,786
Matthew A. Jones, Chief Financial Officer of Atlas Pipeline GP	2007	$ 135,000		$ 356,912	$ 409,128	$ 900,000	$ 75,062(4)	$ 1,875,977
	2006	$ 105,000	$ 210,000	$ 276,546	$ 16,972		$ 7,650	$ 616,168
Jonathan Z. Cohen, Vice Chairman of Atlas Pipeline GP	2007	$ 215,217		$ 807,707	$ 203,667	$ 1,434,783	$ 153,906(5)	$ 2,815,280
	2006	$ 190,000		$ 439,563	$ 48,527		$ 20,400	$ 698,490
Robert R. Firth, Chief Operating Officer & President of Atlas Pipeline Mid-Continent	2007	$ 250,000		$ 12,370,293	$ 443,393	$ 50,000	$ 118,512(6)	$ 13,232,198
	2006	$ 250,000	$ 150,000	$ 1,806,506	$ 61,100			$ 2,267,606
Michael Staines, President	2007	$ 191,250	$ 42,500	$ 61,148	$ 19,198		$ 21,770(7)	$ 336,136

(1) Represents the dollar amount of (i) expense recognized by Atlas Pipeline Holdings for financial statement reporting purposes with respect to phantom units granted under the AHD Plan; and/or (ii) expense we recognized for financial statement reporting purposes with respect to phantom units granted under our Plan and our incentive compensation arrangements, all in accordance with FAS 123R. See note 13 to our consolidated financial statements for an explanation of the assumptions we make for this valuation.

(2) Represents the dollar amount of (i) expense recognized by Atlas America for financial statement reporting purposes with respect to options granted under the Atlas Plan; and/or (ii) expense recognized for financial statement reporting purposes by Atlas Pipeline Holdings for options granted under the AHD Plan, all in accordance with FAS 123R.

(3) Represents payments on DERs of $ 156,012 with respect to the phantom units awarded under our Plan and $97,200 with respect to phantom units awarded under the AHD Plan.

(4) Includes payments on DERs of $ 53,462 with respect to the phantom units awarded under our Plan and $ 21,600 with respect to phantom units awarded under the AHD Plan.

(5) Represents payments on DERs of $105,306 with respect to the phantom units awarded under our Plan and $48,600 with respect to phantom units awarded under the AHD Plan.

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(6) Represents payments on DERs of $67,912 with respect to the phantom units awarded under our Plan and our incentive compensation arrangements, and $48,600 with respect to phantom units awarded under the AHD Plan.

(7) Represents payments on DERs with respect to the phantom units awarded under our Plan.

No awards were granted to our named executive officers under the AHD Plan or the Atlas Plan in 2007.

2007 GRANTS OF PLAN-BASED AWARDS TABLE

Name	Grant Date	Approval Date	All Other Stock Awards: Number of Shares Of Stock or Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ /Sh)	Grant Date Fair Value of Stock and Option Awards
Robert R. Firth	1/24/07	1/22/07	23,000(1)		$ 42.85	$ 2,306,000(3)

(1) Represents grants of phantom units under our Plan, which vest 25% per year on the anniversary of the grant date, valued in accordance with FAS 123R at the closing price of our common units on the grant date of $42.85.

Employment Agreement

Atlas America entered into an employment agreement in July 2004 with Robert R. Firth in connection with our acquisition of Spectrum, pursuant to which he serves as president of our Mid-Continent operations. The agreement expired on July 16, 2007. The agreement provides for initial base compensation of $200,000 per year, subject to increase, but not decrease, at the discretion of the board of directors of Atlas America. Mr. Firth is eligible to receive discretionary bonuses in the discretion of the Atlas America board. Mr. Firth is also entitled to receive awards under our executive group incentive program, described below. Mr. Firth s current allocation under this program is 40%, but the allocation is subject to change at Mr. Firth s election.

The agreement restricts Mr. Firth, for 18 months following the expiration of his employment agreement, from engaging in any business in direct competition with Atlas America and located in the counties in which Atlas Pipeline Mid-Continent, LLC maintains operations or in which Mr. Firth worked; soliciting any of Atlas America s clients; recruiting, soliciting or hiring any of Atlas America s employees or consultants; or inducing any employee or consultant to terminate its relationship with Atlas America. Pursuant to the terms of the grant agreements related to Mr. Firth s stock and option awards, upon Mr. Firth s death or disability, the stock and options awards will automatically vest.

Our Long-Term Incentive Plan

We have a Long-Term Incentive Plan for 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 the Atlas America compensation committee, under delegation from our general partner s managing board which sets the terms of awards under it. Under our Plan, the compensation committee may make awards of either phantom units or options covering an aggregate of 435,000 common units.

A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the compensation committee, cash equivalent to the value of a common 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.

Each non-employee manager of our general partner is awarded the lesser of 500 phantom units, with DERs, or that number of phantom units, with DERs, equal to $15,000 divided by the then fair market value of a common unit for each year of service on the managing board beginning when the plan is adopted by our unitholders. Up to 10,000 phantom units may be awarded to non-employee managers. Except for phantom units awarded to non-employee managers of our general partner, the compensation committee will determine the vesting period for phantom units and the exercise period for options. Phantom units awarded to non-employee managers will generally vest over a 4-year period at the rate of 25% per year. Both types of awards will automatically vest upon a change of control, defined as follows:

Atlas Pipeline Partners GP (or an affiliate of Atlas America) 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 the 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 spin off of the parent, if Edward E. Cohen and Jonathan Z. Cohen cease to be directors of the parent.

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 plan.

The compensation committee may terminate our Plan at any time with respect to any of the common units for which it has not made a grant. In addition, the compensation committee may amend our Plan 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 our Plan, including amendments to increase the number of common units issuable under it. In May 2007, Atlas America s stockholders approved an amendment to our Plan which provides for performance-based awards criteria for purposes of complying with Section 162(m) of the Internal Revenue Code (Section 162(m)).

Executive Group Incentive Program

In connection with our acquisition of Spectrum, and our retention of certain Spectrum s executive officers, we created an executive group incentive program for our Mid-Continent operations. Eligible participants in the executive group incentive program are Robert R. Firth, David D. Hall and such other of our officers as agreed upon by Messrs. Firth and Hall and the managing board of our general partner. The executive group incentive program has three award components: base incentive, additional incentive and acquisition look-back incentive, as follows:

- Base incentive. An award of 29,412 of our common units on the day following the earlier to occur of the filing of our quarterly report on Form 10-Q for the quarter ending September 30, 2007 or a change in control if the following conditions are met:

  - distributable cash flow (defined as earnings before interest, depreciation, amortization and any allocation of overhead from us, less maintenance capital expenditures on the Spectrum assets) generated by the Spectrum assets, as expanded since our acquisition of them, has averaged at least 10.7%, on an annualized basis, of average gross long term assets (defined as total assets less current assets, closing costs associated with any acquisition and plus accumulated depreciation, depletion and amortization) over the 13 quarters ending September 30, 2007 and

  - there having been no more than 2 quarters with distributable cash flow of less than 7%, on an annualized basis, of gross long term assets for that quarter.

- Additional incentive. An award of our common units, promptly upon the filing of our September 30, 2007 Form 10-Q, in an amount equal to 7.42% of the base incentive for each 0.1% by which average annual distributable cash flow exceeds 10.7% of average gross long term assets, as described above, up to a maximum of an additional 29,412 common units.

- Acquisition look-back incentive. If the requirements for the base incentive have been met, an award of our common units determined by dividing (x) 1.5% of the imputed value of the Elk City system, plus 1.0% of the imputed value of all Mid-Continent acquisitions completed before December 31, 2007 that were identified by members of our Mid-Continent executive group by (y) the average closing price of our common units for the 5 trading days before December 31, 2008. Imputed value of an acquisition is equal to the distributable cash flow generated by the acquired entity during the 12 months ending December 31, 2008 divided by the yield. Yield is determined by dividing (i) the sum of our quarterly distributions for the quarter ending December 31, 2008 multiplied by 4 by (ii) the closing price of our common units on December 31, 2008.

The executive group incentive program awards will be allocated among members of the executive group at the discretion of Mr. Firth, provided that no member may receive more than 60% of the total compensation provided under the program.

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AHD Plan

The AHD Plan provides performance incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners who perform services for Atlas Pipeline Holdings. The AHD Plan is administered by Atlas America s compensation committee under delegation from the Atlas Pipeline Holdings board. The compensation committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive an Atlas Pipeline Holdings common unit upon vesting of the phantom unit or, at the discretion of the compensation committee, cash equivalent to the then fair market value of a common unit. In tandem with phantom unit grants, the compensation committee may grant a DER. The compensation committee determines the vesting period for phantom units. Through December 31, 2007, phantom units granted under the AHD Plan generally vest 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant.

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 compensation committee on the date of grant of the option. The compensation committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Through December 31, 2007, unit options generally will vest 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant.

The vesting of both types of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the compensation committee, although no awards currently outstanding contain any such provision. Awards will automatically vest upon a change of control, as defined in the AHD Plan. In May 2007, Atlas s stockholders approved an amendment to the AHD Plan which provides for performance-based awards criteria for purposes of complying with Section 162(m).

Atlas Plan

The Atlas Plan authorizes the granting of up to 2.0 million shares of Atlas common stock to its employees, affiliates, consultants and directors in the form of incentive stock options, non-qualified stock options, stock appreciation rights (SARs), restricted stock and deferred units. SARs represent a right to receive cash in the amount of the difference between the fair market value of a share of Atlas America common stock on the exercise date and the exercise price, and may be free-standing or tied to grants of options. A deferred unit represents the right to receive one share of Atlas common stock upon vesting. Awards under the Atlas Plan generally become exercisable as to 25% each anniversary after the date of grant, except that deferred units awarded to our non-executive board members vest 33 1/3% on the second, third and fourth anniversaries of the grant, and expire not later than ten years after the date of grant. Units will vest sooner upon a change in control of Atlas America or death or disability of a grantee, provided the grantee has completed at least six months service.

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As required by SEC guidelines, the following table disclosed awards under our Plan as well as under the AHD Plan and the Atlas Plan.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

	Option Awards				Stock Awards	
Name	**Number of Securities Underlying Unexercised Options (#) Exercisable**	**Number of Securities Underlying Unexercised Options (#) Unexercisable**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)**
Edward E. Cohen	675,000(1)		$ 16.98	7/1/2015	31,250 (2)	$ 1,339,062 (3)
		500,000(4)	$ 22.56	11/10/2016	90,000 (5)	$ 2,441,700 (6)
Matthew A. Jones	90,000(7)	90,000(8)	$ 16.98	7/1/2015	11,250 (9)	$ 482,062 (3)
		100,000(10)	$ 22.56	11/10/2016	20,000 (11)	$ 542,600 (6)
Jonathan Z. Cohen	450,000(12)		$ 16.98	7/1/2015	21,250 (13)	$ 910,562 (3)
		200,000(14)	$ 22.56	11/10/2016	45,000 (15)	$ 1,220,850 (6)
Robert R. Firth		22,500(16)	$ 16.98	7/1/2015	18,750 (17)	$ 803,438 (3)
		360,000(18)	$ 22.56	11/10/2016	45,000 (19)	$ 1,220,850(6)
Michael L. Staines	5,624(20)	5,626(21)	$ 16.98	7/1/2015	4,000 (22)	$ 171,400(3)

(1) Represents 675,000 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America, which vested immediately. Reflects a 3-for-2 stock split which was effected on May 29, 2007.

(2) Represents our phantom units, which vest as follows: 3/16/08 5,000; 6/8/08 6,250; 11/1/08 5,000; 3/16/09 5,000; 11/1/09 5,000 and 11/1/10 5,000.

(3) Based on closing market price of our common units on December 31, 2007 of $42.85.

(4) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 125,000 and 11/10/10 375,000.

(5) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 22,500 and 11/10/10 67,500.

(6) Based on closing market price of Atlas Pipeline Holdings common units on December 31, 2007 of $27.13.

(7) Represents 90,000 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America. Reflects a 3-for-2 stock split which was effected on May 29, 2007.

(8) Represents options to purchase Atlas America stock, which vest as follows: 7/1/08 45,000 and 7/1/09 45,000.

(9) Represents our phantom units, which vest as follows: 3/16/08 3,750; 11/1/08 1,250; 3/16/09 3,750; 11/1/09 1,250 and 11/1/10 1,250.

(10) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 25,000 and 11/10/10 75,000.

(11) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 5,000 and 11/10/10 15,000.

(12) Represents 450,000 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America, which vested immediately. Reflects a 3-for-2 stock split which was effected on May 29, 2007.

(13) Represents our phantom units, which vest as follows: 3/16/08 3,125; 6/8/08 3,750; 11/1/08 3,750; 3/16/09 3,125; 11/1/09 3,750 and 11/1/10 3,750.

(14) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 50,000 and 11/10/10 150,000.

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(15) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 11,250 and 11/10/10 33,750.
(16) Represents options to purchase Atlas America stock, which vest as follows: 7/1/08 11,250 and 7/1/09 11,250.
(17) Represents our phantom units, which vest as follows: 3/16/08 750; 1/24/09 5,750; 3/16/09 750; 1/24/10 5,750 and 1/24/11 5,750.
(18) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 90,000 and 11/10/10 270,000.
(19) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 11,250 and 11/10/10 33,750.
(20) Represents 5,624 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America. Reflects a 3-for-2 stock split which was effected on May 29, 2007.
(21) Represents options to purchase Atlas America stock, which vest as follows: 7/1/08 2,813 and 7/1/09 2,813.
(22) Represents our phantom units, which vest as follows: 3/16/08 1,000; 6/8/08 2,000; and 3/16/09 1,000.

2007 OPTION EXERCISES AND STOCK VESTED TABLE

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting	Value Realized on Vesting ($)
Edward E. Cohen			16,250(1)	$ 818,500
Matthew A. Jones			5,000(1)	$ 239,375
Jonathan Z. Cohen			10,625(1)	$ 533,787
Robert R. Firth	22,500	$ 701,550	750(2)	$ 36,750
Michael L. Staines			750(1)	$ 36,750

(1) Represents awards under our Plan.
(2) Represents options to purchase Atlas America common stock.

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Tony C. Banks	$ 35,000	$ 13,514(3)	$ 3,541	$ 52,055
Curtis D. Clifford	$ 35,000	$ 15,799(4)	$ 3,433	$ 54,232
Gayle P.W. Jackson	$ 35,000	$ 12,120(5)	$ 2,761	$ 49,881
Martin Rudolph	$ 35,000	$ 12,120(5)	$ 2,761	$ 49,881

(1) Represents the dollar amount of expense we recognized for financial statement reporting purposes with respect to phantom units granted under our Plan in accordance with FAS 123R.
(2) Represents payments on DERs with respect to the phantom units awarded under our Plan.
(3) Represents 307 phantom units granted to Mr. Banks. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 2/11/09 77; 2/11/10 77; 2/13/11 77.
(4) Represents 303 phantom units granted to Mr. Clifford. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 5/10/08 75; 5/10/09 76; 5/10/10 76; 5/10/11 76.

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(5) Represents 315 phantom units granted to each of Ms. Jackson and Mr. Rudolph. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 3/17/08 78; 3/17/09 78; 3/17/10 78; 3/17/11 79.

Our general partner does not pay additional remuneration to officers or employees of Atlas America who also serve as managing board members. In fiscal year 2007, each non-employee managing board member received an annual retainer of $35,000 in cash and an annual grant 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) pursuant to our Long-Term Incentive Plan. In addition, our general partner reimburses each non-employee board member for out-of-pocket expenses in connection with attending meetings of the board or committees. We reimburse our general partner for these expenses and indemnify our general partner s managing board members for actions associated with serving as managing board members to the extent permitted under Delaware law.

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

The following table sets forth the number and percentage of shares of common stock owned, as of February 25, 2008, 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.

Name of Beneficial Owner	Common Units	Percent of Class
Members of the Managing Board		
Edward E. Cohen	42,850(1)	*
Jonathan Z. Cohen	29,352(2)	*
Michael L. Staines	7,000(3)	*
Matthew A. Jones	12,500(4)	*
Tony C. Banks	653	*
Curtis D. Clifford	639	*
Gayle P.W. Jackson	491(5)	*
Martin Rudolph	991(6)	*
Executive Officers		
Robert R. Firth	18,200(7)	*
Executive officers and managing board members as a group (9 persons)	112,676	*
Other Owners of More than 5% of Outstanding Units		
Atlas Pipeline Holdings, L.P.	3,835,227	9.89%
Leon Cooperman	2,597,718(8)	6.70%
Deutsche Bank AG	2,801,981(9)	7.24%
Swank Capital, LLC	3,066,831(10)	7.93%

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* Less than 1%.

(1) This amount includes 5,000 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(2) This amount includes 3,125 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(3) This amount includes 1,000 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(4) This amount represents 3,750 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(5) This amount represents 246 phantom units which vest in 60 days and which, upon vesting, may be converted into an equal number of our common units or into their then fair market value in cash.

(6) This amount includes 246 phantom units which vest in 60 days and which, upon vesting, may be converted into an equal number of our common units or into their then fair market value in cash.

(7) This amount includes 750 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(8) This information is based upon a Schedule 13G/A which was filed with the SEC on February 4, 2008. The address Mr. Cooperman is 88 Pine Street, Wall Street Plaza 31st Floor, New York, NY 10005.

(9) This information is based upon a Schedule 13G which was filed with the SEC on February 4, 2008. The address for Deutsche Bank AG is Theodor-Heuss-Allee 70, 60468 Frankfurt am Main, Federal Republic of Germany.

(10) This information is based upon a Schedule 13G which was filed with the SEC on February 14, 2008. The address for Swank Capital, LLC is 330 Oak Lawn Avenue, Suite 650, Dallas, TX 75219.

Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2007:

Plan category	(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders phantom units	129,746	n/a	208,055

The following table contains information about the AHD Plan as of December 31, 2007:

Plan category		(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders phantom units		220,825	n/a	
Equity compensation plans approved by security holders	unit options	1,215,000	$ 22.56	
Equity compensation plans approved by security holders	Total	1,435,825		663,800

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The following table contains information about the Atlas Plan as of December 31, 2007:

Plan category		(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	restricted units	4,263	$ 0.00	
Equity compensation plans approved by security holders	options	1,810,254	$ 18.15	
Equity compensation plans approved by security holders	Total	1,814,517		1,112,565

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

We do not directly employ any persons to manage or operate our business. These functions are provided by our general partner and employees of Atlas America. 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 Atlas America 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 Atlas America based on the number of its employees who devote substantially all of their time to our activities. Our partnership agreement provides that our general partner will determine the costs and expenses that are allocable to us in any reasonable manner determined at its sole discretion. We reimbursed our general partner and its affiliates $5.9 million for the year ended December 31, 2007 for compensation and benefits related to their employees, and reimbursed $26.4 million for other indirect costs, including certain costs that we capitalized. Our general partner believes that the method utilized in allocating costs to us is reasonable.

Our omnibus agreement and the natural gas gathering agreements with Atlas America and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), were not the result of arms-length negotiations and, accordingly, we cannot assure you that we could have obtained more favorable terms from independent third parties similarly situated. However, since these agreements principally involve the imposition of obligations on Atlas America and its affiliates, we do not believe that we could obtain similar agreements from independent third parties.

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ending December 31, 2007 and 2006 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2007	2006
Audit fees [1]	$ 1,642,981	$ 1,318,838
Audit related fees		
Tax fees [2]	180,568	94,973

Total aggregate fees billed	$ 1,823,549	$ 1,413,811

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(1) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements and the review of financial statements included in Form 10-Q. The fees are for services that are normally provided by Grant Thornton LLP in connection with statutory or regulatory filings or engagements.

(2) Represents the aggregate fees recognized in each of the last two years 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 2007.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 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	Master Formation Agreement between Atlas Pipeline Partners, L.P. and Western Gas Resources, Inc to form Atlas Pipeline Mid-Continent WestTex, LLC dated June 1, 2007[1]
2.1(a)	Amendment to Master Formation Agreement[2]
2.2	Master Formation Agreement between Atlas Pipeline Partners, L.P. and Western Gas Resources, Inc and Western Gas Resources Westana, Inc. to form Atlas Pipeline Mid-Continent WestOk, LLC dated June 1, 2007[1]
2.2(a)	Amendment to Master Formation Agreement[2]
3.1	Certificate of Limited Partnership[3]
3.2	Second Amended and Restated Agreement of Limited Partnership[4]
3.2(a)	Amendment No. 1 to Second Amendment and Restated Agreement of Limited Partnership[5]
3.2(b)	Amendment No. 1 to Second Amendment and Restated Agreement of Limited Partnership[2]

3.3	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units [6]
3.3(a)	Amended and Restated Certificate of Designation[7]
4.1	Common unit certificate[1]
10.1	Purchase Agreement between Atlas Pipeline Partners, L.P. and Sunlight Capital Partners, LLC dated April 8, 2007[6]
10.2	Registration Rights Agreement between Atlas Pipeline Partners, L.P. and Sunlight Capital Partners, LLC dated April 8, 2007[6]

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10.3	Common Unit Purchase Agreement among Atlas Pipeline Partners, L.P. and the purchasers named therein dated June 1, 2007(1)
10.4	Revolving Credit and Term Loan Agreement dated July 27, 2007(2)
10.5	Operating Agreement of Atlas Pipeline Mid-Continent WestTex, LLC dated July 27, 2007(2)
10.6	Operating Agreement of Atlas Pipeline Mid-Continent WestOk, LLC dated July 27, 2007(2)
10.7	Purchase Option Agreement between Atlas Pipeline Mid-Continent WestTex, LLC and Pioneer Natural Resources USA, Inc. dated July 27, 2007(2)
10.8	Registration Rights Agreement dated July 27, 2007(2)
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
14.1	Pre-Clearance Procedures Memorandum, as amended October 23, 2007(8)
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 current report on Form 8-K on June 5, 2007.
(2) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(3) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(4) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(5) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(6) Previously filed as an exhibit to current report on Form 8-K on March 14, 2006.
(7) Previously filed as an exhibit to current report on Form 8-K on April 19, 2007.
(8) Previously filed as an exhibit to current report on Form 8-K on October 26, 2007.

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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 29, 2008

By: /s/ EDWARD E. COHEN
Chairman of the Managing Board

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 29, 2008.

/s/ EDWARD E. COHEN Edward E. Cohen	Chairman of the Managing Board of the General Partner Chief Executive Officer of the General Partner
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Vice Chairman of the Managing Board of the General Partner
/s/ MICHAEL L. STAINES Michael L. Staines	President, Chief Operating Officer, and Managing Board Member of the General Partner
/s/ MATTHEW A. JONES Matthew A. Jones	Chief Financial Officer of the General Partner
/s/ SEAN P. MCGRATH Sean P. McGrath	Chief Accounting Officer of the General Partner
/s/ TONY C. BANKS Tony C. Banks	Managing Board Member of the General Partner
/s/ CURTIS D. CLIFFORD Curtis D. Clifford	Managing Board Member of the General Partner
/s/ GAYLE P.W. JACKSON Gayle P.W. Jackson	Managing Board Member of the General Partner
/s/ MARTIN RUDOLPH Martin Rudolph	Managing Board Member of the General Partner