ATLAS PIPELINE PARTNERS LP
Form 10-K
March 14, 2007

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, 2006

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.)**
311 Rouser Road	**15108**

Moon Township, Pennsylvania	
(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 ¨ No x

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 $40.91 per common limited partner unit on June 30, 2006, was approximately $468.0 million.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-K

FORWARD-LOOKING STATEMENTS

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

- *the 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 and a midstream energy services provider engaged in the transmission, gathering and processing of natural gas. We are a leading provider of natural gas gathering services in the Anadarko Basin and Golden Trend area of the 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. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas and southeastern Missouri. We conduct our business through two operating segments: our Mid-Continent operations and our Appalachian operations.

We own and operate through our Mid-Continent operations:

- 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 322 million cubic feet per day (MMcfd);

- three natural gas processing plants with aggregate capacity of approximately 350 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, all located in Oklahoma; and

- 1,900 miles of active natural gas gathering systems located in Oklahoma, Arkansas, northern Texas and the Texas panhandle, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or Ozark Gas Transmission.

We own and operate through our Appalachian operations 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) 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.

On July 26, 2006, Atlas America contributed its ownership interests in Atlas Pipeline Partners GP, LLC, our general partner, to Atlas Pipeline Holdings, L.P. (Atlas Pipeline Holdings - NYSE: AHD), a then wholly-owned subsidiary of Atlas America. Concurrent with this transaction, Atlas Pipeline Holdings issued 3,600,000 common units, representing a 17.1% ownership interest, in an initial public offering at a price of $23.00 per unit. Net proceeds from this offering were distributed to Atlas America.

Since our initial public offering in January 2000, we have completed six acquisitions at an aggregate cost of approximately $590.1 million, including, in two separate transactions, our acquisition of 100% of NOARK Pipeline System, Limited Partnership (NOARK). In October 2005, we acquired Atlas Arkansas Pipeline LLC (Atlas Arkansas), which owned a 75% interest in NOARK, and in May 2006, we acquired the remaining 25% interest in NOARK from Southwestern Energy Company (Southwestern).

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 7,200 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. We intend to increase the portion of the transmission services provided under long-term contracts. 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, such as the construction of the Sweetwater gas processing plant and gathering system (Sweetwater plant), that increase distributable cash flow. The Sweetwater plant, which began operations in September 2006, is located west of our Elk City gas plant in Beckham County, Oklahoma and has an operating capacity of 120 MMcfd. The Sweetwater plant was built to further access natural gas production actively being developed in western Oklahoma and the Texas panhandle.

Contracts and Customer Relationships

In our Mid-Continent operations, we either purchase natural gas from producers, or intermediaries, and move the natural gas into receipt points on our systems and then sell the natural gas and produced natural gas liquids (NGLs), if any, off of delivery points on our systems, or we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Beyond the distinction of purchasing or transporting natural gas, we have a variety of contractual relationships with our producers and shippers, including fixed-fee, percentage-of-proceeds and keep-whole. Ozark Gas Transmission s revenues are comprised of FERC-regulated transmission fees that are based on firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates. Under the fixed-fee contracts, we provide gathering, compression, treating and dehydration services to our customers for a flat fee. Gross margin from fee-based services depends solely on throughput volume and is not affected by changes in commodity prices. Under the percentage-of-proceeds contracts, we purchase natural gas at the wellhead, process the natural gas and sell the plant residue natural gas and NGLs at market-based prices, remitting to producers a percentage of the proceeds. Under keep-whole contracts, we gather natural gas from the producer, process the natural gas and sell the resulting NGLs at market price. The extraction of the NGLs lowers the British thermal unit (Btu) content of the natural gas. Therefore, under keep-whole contracts, we must replace these Btus by either purchasing natural gas at market prices or making a cash payment to the producer. Our profitability is dependent upon the spread between the price of natural gas, our feedstock, and NGLs, our manufactured product. The gross margin associated with each of these contractual arrangements can vary from period to period due to a variety of factors, including changing prices of natural gas and NGLs, producers optionality between contract types (e.g., percentage-of-proceeds and keep-whole), and producers optionality between transporting and selling natural gas.

Substantially all of the natural gas we transport in our Appalachian operations is under a percentage-of-proceeds contract with Atlas Energy where we calculate our transportation fee as a percentage of the price of the natural gas we transport. The natural gas we transport in our Appalachian operations does not require processing.

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, 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.

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.

Our Mid-Continent Operations

We own and operate a 565-mile interstate natural gas pipeline, approximately 2,700 miles of intrastate natural gas gathering systems, including approximately 800 miles of inactive pipeline, located in Oklahoma, Arkansas, southeastern Missouri, northern Texas and the Texas panhandle, and three processing plants and one stand-alone treating facility in Oklahoma. Our Mid-Continent operations were formed through our acquisition of Spectrum Field Services, Inc. (Spectrum), also referred to as our Velma system, in July 2004 and expanded through our acquisition of ETC Oklahoma Pipeline, Ltd. (Elk City) in April 2005 and the NOARK acquisition, which was consummated in two separate transactions in October 2005 and May 2006. 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 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 1,350 receipt points, consisting primarily of individual connections and, secondarily, of 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, Texas Eastern Transmission Corp. 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 North and West 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

We own NOARK, which includes Ozark Gas Transmission, a 565-mile FERC-regulated natural gas interstate pipeline extending from southeastern Oklahoma through Arkansas and into southeastern Missouri. 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, Ozark Gas Gathering and ONEOK Gas Transmission.

Mid-Continent Gathering Systems

Velma. The Velma gathering system is located in the Golden Trend area of Southern Oklahoma and the Barnett Shale area of North Texas. As of December 31, 2006, the gathering system had approximately 1,080 miles of active pipeline with approximately 640 receipt points consisting primarily of individual connections and, secondarily, of 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.

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. The Elk City and Sweetwater gathering system connects to over 360 receipt points, with a majority of the western end of the system located in close proximity to areas of high drilling activity.

Ozark Gas Gathering. NOARK owns 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 Shale. This system connects to approximately 300 receipt points and compresses and transports gas to interconnections with Ozark Gas Transmission.

Processing Plants

Velma. The Velma processing plant, located in Stephens County, Oklahoma, is a single-train twin-expander 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 gas. We sell natural gas to various purchasers at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbons Company. Our Velma operations gather and process natural gas for approximately 120 producers. We have electric-powered compressors at the Velma plant rather than higher-cost and less efficient natural gas-powered compressors used by many of our competitors, which results in additional profitability from higher efficiency and lower fuel costs.

Elk City. The Elk City processing plant, located in Beckham County, Oklahoma, is a twin-train cryogenic natural gas processing plant with a total capacity of approximately 130 MMcfd. We sell natural gas to various purchasers at the tailgate of our Elk City processing plant and sell NGL production to ONEOK Hydrocarbons Company. The Prentiss gas treating facility is an amine treating facility with a total capacity of approximately 200 MMcfd. The Elk City, Sweetwater and Prentiss facilities are on the same gathering system and are referred to as our Elk City operations. Our Elk City operations gather and process gas for more than 140 producers.

Sweetwater. The Sweetwater processing plant, which initiated operations in September 2006, is a single-train cryogenic natural gas processing plant located in Beckham County, Oklahoma, near the Elk City processing plant, with a total capacity of approximately 120 MMcfd. We sell natural gas to purchasers at the tailgate of our Sweetwater processing plant and sell NGL production to ONEOK Hydrocarbons Company.

Enville. Our Enville, Oklahoma natural gas plant is currently inactive and is used as a field compression booster station.

Natural Gas Supply

In the Mid-Continent, we have natural gas purchase, gathering and processing agreements with approximately 260 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, 2006, 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 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 and 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 and Enogex, Inc. At our Elk City and 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 Texas Eastern East LA index as published in *Inside FERC* and natural gas sales have historically been to affiliates of Enogex and Southwestern.

We sell our NGL production to ONEOK Hydrocarbons Company under two separate agreements. The Velma agreement has an initial term expiring February 1, 2011, the Elk City and Sweetwater agreement has an initial term expiring October 1, 2008 and NGLs 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 sold for our account to SemGroup, L.P. and EnerWest Trading, while condensate collected at Elk City and Sweetwater is sold to TEPPCO Crude Oil, L.P.

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.

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, 2006, 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 5,865 wells with an average throughput of 61.9 MMcfd of natural gas for the year ended December 31, 2006. 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.

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 an 82.9% 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. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a 19.4% ownership interest, in an initial public offering at a price of $21.00 per unit. 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, 2006, we connected 2,846 new wells to our Appalachian gathering system, 433 of which were added through acquisitions of other gathering systems. For the year ended December 31, 2006, we connected 711 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, 2006, we received gathering fees averaging $1.34 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. 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 81.6% of Atlas Energy and also owns 82.9% of Atlas Pipeline Holdings, the parent of our general partner, which owns an 11.5% 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 5,290 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, 2006, Atlas Energy and its affiliates raised $218.5 million from investors and drilled 648 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

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 an 82.9% interest in Atlas Pipeline Holdings.

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.

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, Eagle Rock Midstream Resources L.P. and Enbridge, Inc. 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, 2006, we connected 26 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;

- 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 not charge rates that have been determined not to be just and reasonable by 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, Texas and Oklahoma 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 regulatory oversight by the Arkansas Public Service 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.

We are currently subject to state ratable take and common purchaser statutes in Texas and Oklahoma. The ratable take statutes generally require gatherers to take, without discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

The state of Oklahoma has adopted a complaint-based statute that allows the Oklahoma Corporation Commission to resolve grievances relating to natural gas gathering access and to remedy discriminatory rates for providing gathering service where the parties are unable to agree. In a similar way, the Texas Railroad Commission sponsors a complaint procedure for resolving grievances about natural gas gathering access and rate discrimination. No such complaints have been made against our Mid-Continent operations to date in Oklahoma or Texas.

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 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 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.

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.

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, or the 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, 2006, 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 three natural gas processing plants, one treating facility, and approximately 3,265 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.

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 188 people at December 31, 2006 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 311 Rouser 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 2006 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 not 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 not 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 revenues from percentage-of-proceeds and keep-whole contracts. As a result, our income depends to a significant extent upon the prices at which the natural gas we transport, treat or process and the natural gas liquids, or NGLs, we produce are sold. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our consolidated income for the year ended December 31, 2007 of approximately $5.3 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 subject to percentage-of-proceeds contracts. 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. 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 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 2006, Chesapeake Energy Corporation, Kaiser-Francis Oil Company, Burlington Resources Inc., St. Mary Land and Exploration Company and Sanguine Gas Exploration, LLC 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.

We currently have three processing plants. If operations at any of our 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 Enogex Inc. operate competing gathering systems in Ozark Gas Gathering s 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.

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.

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 Elk City in April 2005 and 100% of NOARK in two separate transactions during October 2005 and May 2006 and are still 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 Elk City and NOARK, 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.

The process of combining companies or the failure to integrate them successfully could harm our business or future prospects, and result in significant decreases in our gross margin and cash flows.

The acquisitions of our Velma, Elk City and NOARK operations have substantially changed our business, making it difficult to evaluate our business based upon our historical financial information.

The acquisitions of our Velma, Elk City and NOARK operations 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.

Before acquiring our Velma and Elk City operations, we had no previous experience either in the Mid-Continent service area or in operating natural gas processing plants.

Our Mid-Continent gathering systems are located principally in Oklahoma and northern Texas, areas in which we have been involved only since July 2004 as a result of the Velma acquisition and, subsequently, Elk City acquisition in April 2005 and the acquisition of the initial 75% ownership interest in NOARK in October 2005. In addition, as a result of these acquisitions, we began to operate natural gas processing plants, a business in which we had no prior operating experience. We depend upon the experience, knowledge and

business relationships that have been developed by the senior management of our Mid-Continent operations to operate successfully in the region. The loss of the services of one or more members of our Mid-Continent senior management, in particular, Robert R. Firth, President, and David D. Hall, Chief Financial Officer, could limit our growth or ability to maintain our current level of operations in the Mid-Continent region.

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 system, the construction may occur over an extended period of time, and we will not receive any material increases 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 operating capacity. 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 of natural gas from wells 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. We expect that any such regulation would increase our costs, decrease our gross margin and cash flows, or both.

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, and market center 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.

Other state and local regulations will also affect our business. Matters subject to regulation include rates, service and safety. Our gathering lines are subject to ratable take and common purchaser statutes in Texas and Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Federal law leaves any economic regulation of natural gas gathering to the states. 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, in Texas and Oklahoma, with respect to rate discrimination. Should a complaint be filed or regulation by the Texas Railroad Commission or Oklahoma Corporation Commission become more active, our revenues could decrease.

Increased regulatory requirements relating to the integrity of the Ozark Transmission pipeline will require it to spend additional money to comply with these requirements. Ozark Gas Transmission is subject to extensive laws and regulations related to pipeline integrity. For example, 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 not charge rates that have been determined not 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;
- 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, the development of uniform interstate gas quality standards by FERC could create two distinct markets for natural gas an interstate market subject to uniform minimum quality standards and an intrastate market with no uniform 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 to review pipeline contracts. If FERC determines that a term of any such contract deviates in a material manner from a pipeline s tariff, FERC typically will order the pipeline to remove the term from the contract and execute and refile a new contract with FERC or, alternatively, to amend its tariff to include the deviating term, 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 of 2005, 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.

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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.

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 and NGLs. Our hedging activities will vary in scope based upon the level and volatility of natural gas 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 the Occupational Health and Safety Act, or OSHA, and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our 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 an 11% 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.

- 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 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 America.

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.

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, 2006.

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 March 1, 2007, the closing price for the common units was $48.35 and there were 92 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, 2006 and 2005:

	High	Low	Distributions Declared
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
2005			
Fourth Quarter	$ 49.21	$ 39.45	$ 0.83
Third Quarter	$ 49.72	$ 43.75	$ 0.81
Second Quarter	$ 46.39	$ 41.25	$ 0.77
First Quarter	$ 49.00	$ 40.00	$ 0.75

Our partnership agreement requires that we distribute 100% of available cash to our general partner and common limited partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

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

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. The general partner s incentive distributions declared were $14.9 million for the year ended December 31, 2006.

For information concerning units authorized for issuance under our long-term incentive plan, see Item 11, Executive Compensation .

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, 2006, 2005 and 2004 and at December 31, 2006 and 2005 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, 2004, 2003 and 2002 and for the years ended December 31, 2003 and 2002 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

	Years Ended December 31, 2006[1]	2005[2]	2004[3]	2003	2002
	(in thousands, except per unit and operating data)				
Statement of income data:					
Revenue:					
Natural gas and liquids	$ 391,356	$ 338,672	$ 72,364	$	$
Transportation and compression	60,924	30,309	18,800	15,651	10,660
Other income	12,412	2,519	127	98	7
Total revenue and other income	464,692	371,500	91,291	15,749	10,667
Costs and expenses:					
Natural gas and liquids	334,299	288,180	58,707		
Plant operating	15,722	10,557	2,032		
Transportation and compression	12,013	4,053	2,260	2,421	2,062
General and administrative	21,309	13,608	4,643	1,661	1,482
Depreciation and amortization	22,994	13,954	4,471	1,770	1,475
Loss (gain) on arbitration settlement, net		138	(1,457)		
Interest	24,572	14,175	2,301	258	250
Minority interest in NOARK [4]	118	1,083			
Total costs and expenses	431,027	345,748	72,957	6,110	5,269
Net income	33,665	25,752	18,334	9,639	5,398
Premium on preferred unit redemption			(400)		
Preferred unit imputed dividend cost	(1,898)				
Net income attributable to common limited partners and the general partner	$ 31,767	$ 25,752	$ 17,934	$ 9,639	$ 5,398
Net income attributable to common limited partners per unit:					
Basic	$ 1.29	$ 1.86	$ 2.53	$ 2.17	$ 1.54
Diluted	$ 1.27	$ 1.84	$ 2.53	$ 2.17	$ 1.54
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 607,097	$ 445,066	$ 175,259	$ 29,628	$ 23,764
Total assets	786,884	742,726	216,785	49,512	28,515
Total debt, including current portion	324,083	298,625	54,452		6,500
Total partners capital	379,134	329,510	136,704	44,245	19,686
Cash flow data:					
Net cash provided by operating activities	$ 45,144	$ 50,917	$ 25,193	$ 13,702	$ 8,138
Net cash used in investing activities	(104,614)	(411,004)	(151,797)	(9,154)	(5,230)
Net cash provided by/(used in) financing activities	27,028	376,110	129,740	8,671	(3,211)
Other financial data:					
Gross margin [5]	$ 121,321	$ 80,516	$ 32,202	$ 15,651	$ 10,660
EBITDA [6]	80,031	53,146	25,106	11,667	7,123
Adjusted EBITDA [6]	86,346	57,818	25,806	11,667	7,123
Maintenance capital expenditures	$ 4,649	$ 1,922	$ 1,516	$ 3,109	$ 170
Expansion capital expenditures	79,182	50,576	8,527	4,526	5,060
Total capital expenditures	$ 83,831	$ 52,498	$ 10,043	$ 7,635	$ 5,230
Operating data:					
Appalachia:					
Average throughput volumes (Mcfd)	61,892	55,204	53,343	52,472	50,363
Average transportation rate per Mcf	$ 1.34	$ 1.21	$ 0.96	$ 0.82	$ 0.58
Mid-Continent:					

Velma system:			
Gathered gas volume (Mcfd)	60,682	67,075	56,441
Processed gas volume (Mcfd)	58,132	62,538	55,202
Residue gas volume (Mcfd)	45,466	50,880	42,659
NGL volume (Bpd)	6,423	6,643	5,799
Condensate volume (Bpd)	193	256	185
Elk City/Sweetwater system:			
Gathered gas volume (Mcfd)	277,063	250,717	
Processed gas volume (Mcfd)	154,047	119,324	
Residue gas volume (Mcfd)	140,969	109,553	
NGL volume (Bpd)	6,400	5,303	
Condensate volume (Bpd)	140	127	
NOARK system:			
Average Ozark Gas Transmission throughput volume (Mcfd)	249,581	255,777	

(1) Includes our acquisition of the remaining 25% ownership interest in NOARK on May 2, 2006, representing 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.
(2) Includes our acquisition of Elk City on April 14, 2005, representing eight and one-half months operations, and a 75% ownership interest in NOARK on October 31, 2005, representing two months operations, for the year ended December 31, 2005. Operating data for the NOARK system represents 100% of its operating activity.
(3) Includes our acquisition of Spectrum on July 16, 2004, representing five and one-half months operations for the year ended December 31, 2004.
(4) Represents Southwestern s 25% minority interest in the net income of NOARK, which we acquired on May 2, 2006.
(5) 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 to gross margin (in thousands):

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Net income	$ 33,665	$ 25,752	$ 18,334	$ 9,639	$ 5,398
Plus (minus):					
Interest income and other	(6,686)	(894)	(382)	(98)	(7)
Plant operating	15,722	10,557	2,032		
Transportation and compression	12,013	4,053	2,260	2,421	2,062
General and administrative	21,309	13,608	4,643	1,661	1,482
Depreciation and amortization	22,994	13,954	4,471	1,770	1,475
Loss (gain) on arbitration settlement, net		138	(1,457)		
Interest expense	24,572	14,175	2,301	258	250
Minority interest in NOARK	118	1,083			
Minority interest share of gross margin for NOARK	(2,386)	(1,910)			
Gross margin	$ 121,321	$ 80,516	$ 32,202	$ 15,651	$ 10,660

(6) EBITDA represents net income 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 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 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 to EBITDA and EBITDA to Adjusted EBITDA (in thousands):

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Net income	$ 33,665	$ 25,752	$ 18,334	$ 9,639	$ 5,398
Plus:					
Interest expense	24,572	14,175	2,301	258	250
Depreciation and amortization	22,994	13,954	4,471	1,770	1,475
Minority interest share of depreciation and amortization and interest expense for NOARK	(1,200)	(735)			
EBITDA	$ 80,031	$ 53,146	$ 25,106	$ 11,667	$ 7,123
Adjustments:					
Non-cash compensation expense	6,315	4,672	700		

Adjusted EBITDA	$ 86,346	$ 57,818	$ 25,806	$ 11,667	$ 7,123

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 Basin and Golden Trend area of the 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. 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 operating 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 322 MMcfd;

- three natural gas processing plants with aggregate capacity of approximately 350 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, all located in Oklahoma; and

- 1,900 miles of active natural gas gathering systems located in Oklahoma, Arkansas, northern Texas and the Texas panhandle, 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 2006, we have completed six acquisitions at an aggregate cost of approximately $590.1 million, including, most recently:

- 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.

In July 2004, we acquired Spectrum for $141.6 million, including transaction costs and the payment of taxes due as a result of the transaction. Spectrum s principal assets consist of 1,100 miles of active and 800 miles of inactive natural gas gathering pipelines in the Golden Trend area of southern Oklahoma and the Barnett Shale area of North Texas and a natural gas processing facility in Stephens County, Oklahoma, with a total capacity of approximately 100 MMcfd.

Recent Developments

On September 27, 2006, we announced the initiation of operations of our new gas processing plant and gathering system (Sweetwater plant) in Beckham County, Oklahoma. The Sweetwater plant, with a processing capacity of 120 MMcfd, is located west of our Elk City gas plant and was built to further access natural gas production actively being developed in western Oklahoma and the Texas panhandle.

On April 21, 2006, we entered into a three-year transportation contract with Southwestern for additional natural gas transportation on NOARK s Ozark Gas Transmission System. The new transportation agreement adds a firm commitment to transportation volumes increasing to 175.0 million British Thermal units per day (MMbtud) in the latter stages of the contract. This agreement brings the aggregate long-term transportation commitments on the Ozark system to approximately 75% of the certificated capacity once the maximum volume per the agreement is reached. The increased transportation volume will be drawn primarily from the Fayetteville Shale development, located in north central Arkansas along the Ozark pipeline system. As of February 2007, this agreement has been updated to increase the maximum throughput commitment on the contract to 270.0 MMbtud within the same three-year period.

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 current and prior financial statements.

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 selling price of the natural gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf, depending upon the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has always exceeded this minimum in general. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our revenue in the Mid-Continent region is determined primarily by the fees earned from our transmission, gathering and processing operations. We either 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, or 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 services are 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 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 the Elk City/Sweetwater system, which is currently our only gathering system with 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 such type of 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 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 consolidated income for the year ending December 31, 2007 of approximately $5.3 million.

Results of Operations

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

	Years Ended December 31,		
	2006	**2005**	**2004**
Operating data:			
Appalachia:			
Average throughput volumes (Mcfd)	61,892	55,204	53,343
Average transportation rate per Mcf	$ 1.34	$ 1.21	$ 0.96
Mid-Continent:			
Velma system:			
Gathered gas volume (Mcfd)	60,682	67,075	56,441
Processed gas volume (Mcfd)	58,132	62,538	55,202
Residue gas volume (Mcfd)	45,466	50,880	42,659
NGL volume (Bpd)	6,423	6,643	5,799
Condensate volume (Bpd)	193	256	185
Elk City/Sweetwater system:			
Gathered gas volume (Mcfd)	277,063	250,717	
Processed gas volume (Mcfd)	154,047	119,324	
Residue gas volume (Mcfd)	140,969	109,553	
NGL volume (Bpd)	6,400	5,303	
Condensate volume (Bpd)	140	127	
NOARK system:			
Average Ozark Gas Transmission throughput volume (Mcfd)	249,581	255,777	

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 period. 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 and compression 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 $8.0 million to $12.0 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 $7.7 million to $21.3 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.

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 in NOARK 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.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Revenue. Natural gas and liquids revenue was $338.7 million for the year ended December 31, 2005, an increase of $266.3 million from $72.4 million for the prior year. The increase was attributable to revenue contributions from the NOARK system acquired in October 2005 of $14.6 million and the Elk City system acquired in April 2005 of $122.4 million, and an increase of $129.3 million in Velma natural gas and liquids revenue due to a full year s contribution after its acquisition in July 2004 and higher commodity prices. Gross natural gas gathered averaged 67.1 MMcfd on the Velma system for the year ended December 31, 2005, an increase of 19% from the prior period from its date of acquisition through December 31, 2004. Gross natural gas gathered on the Elk City system averaged 250.7 MMcfd from its date of acquisition through December 31, 2005. For the NOARK system, average throughput volume was 255.8 MMcfd from October 31, 2005, its date of acquisition, to December 31, 2005. 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 and compression revenue increased to $30.3 million for the year ended December 31, 2005 from $18.8 million for the prior year. This $11.5 million increase was primarily due to contributions from the transportation revenues associated with the NOARK system acquired in October 2005 of $5.5 million and increases in the Appalachia system average transportation rate earned and volume of natural gas transported. Our Appalachia system average transportation rate was $1.21 per Mcf for the year ended December 31, 2005 as compared with $0.96 per Mcf for the prior year, an increase of $0.25 per Mcf. The Appalachia system s average throughput volume was 55.2 MMcfd for the year ended December 31, 2005 as compared with 53.3 MMcfd for the prior year, an increase of 1.9 MMcfd. The increase in the Appalachia system s 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 our derivatives, was $2.5 million for the year ended December 31, 2005, an increase of $2.4 million from the prior year. The increase was due mainly to a $1.9 million increase in the gain recognized on the ineffective portion of our qualifying derivatives.

Costs and Expenses. Natural gas and liquids cost of goods sold of $288.2 million and plant operating expenses of $10.6 million for the year ended December 31, 2005 represented increases of $229.5 million and $8.5 million, respectively, from the prior year amounts due primarily to the acquisitions and an increase in commodity prices. Transportation and compression expenses increased $1.8 million to $4.1 million for the year ended December 31, 2005 due mainly to NOARK system operating costs from its date of acquisition 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 $13.6 million for the year ended December 31, 2005 compared with $4.6 million for the prior year. This increase was mainly due to a $4.0 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 acquisitions and capital raising opportunities. Depreciation and amortization increased to $14.0 million for the year ended December 31, 2005 compared with $4.5 million for the prior year due principally to the increased asset base associated with the acquisitions.

Interest expense increased to $14.2 million for the year ended December 31, 2005 as compared with $2.3 million for the prior year. This $11.9 million increase was primarily due to interest associated with borrowings under our credit facility to finance our acquisitions and $1.0 million of accelerated amortization of deferred financing costs. This accelerated amortization was associated with the retirement of the term portion of our credit facility in April 2005.

Net gain on arbitration settlement of $1.5 million for the year ended December 31, 2004 is the result of a December 30, 2004 settlement agreement with SEMCO settling all issues and matters related to our terminated acquisition of Alaska Pipeline Company from SEMCO. The gain reflects $5.5 million received from SEMCO, net of $4.0 million of associated costs.

Minority interest in NOARK of $1.1 million for the year ended December 31, 2005 represents Southwestern s 25% ownership interest in the net income of NOARK from the date of acquisition on October 31, 2005 through December 31, 2005. Our financial results include the consolidated financial statements of NOARK from the date of its acquisition through December 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, 2006, we had $38.0 million of outstanding borrowings under our credit facility and $8.1 million of outstanding letters of credit which are not reflected as borrowings on our consolidated balance sheet, and $178.9 million of remaining committed capacity under the $225.0 million credit facility, subject to covenant limitations (see 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, 2006. At December 31, 2006, we had a working capital position of $1.2 million compared with a working capital position of $16.8 million at December 31, 2005. This decrease was primarily attributable to the utilization of cash, principally raised through financing transactions during 2005, to fund expansion capital expenditures incurred during the year ended December 31, 2006, including the construction of the Sweetwater plant. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, quarterly cash distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. 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, 2006 Compared to Year Ended December 31, 2005

Net cash provided by operating activities of $45.1 million for the year ended December 31, 2006 represented a decrease of $5.8 million from $50.9 million for the prior year. The decrease was derived principally from a $16.5 million decrease in cash flows resulting from changes in the components of working capital, 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. These amounts were partially offset by increases in net income of $7.9 million and depreciation and amortization of $9.0 million. The decrease in cash resulting from changes in the components of working capital was the result of working capital required for the operations of NOARK and Elk City. The increases in net income and depreciation and amortization were principally due to the contributions from the NOARK and Elk City acquisitions.

Net cash used in investing activities was $104.6 million for the year ended December 31, 2006, a decrease of $306.4 million from $411.0 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 $31.3 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.

Cash Flows - Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Net cash provided by operating activities of $50.9 million for the year ended December 31, 2005 increased $25.7 million from $25.2 million for the prior year. The increase is derived principally from increases in net income of $7.8 million, depreciation and amortization of $9.5 million, non-cash compensation expense of $4.0 million, and amortization of deferred financing costs of $1.7 million. The increases in net income and depreciation and amortization were principally due to the contribution from the acquisitions of Spectrum in July 2004, Elk City in April 2005, and NOARK in October 2005.

Net cash used in investing activities was $411.0 million for the year ended December 31, 2005, an increase of $259.2 million from $151.8 million for the prior year. This increase was principally due to the acquisitions mentioned previously and a $42.5 million increase in capital expenditures. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $376.1 million for the year ended December 31, 2005, an increase of $246.4 million from $129.7 million for the prior year. This increase was principally due to the $243.1 million of net proceeds from the issuance of $250.0 million of 10-year, 8.125% senior unsecured notes in December 2005, which were primarily utilized to repay indebtedness incurred under our credit facility to partially fund our acquisitions, and $119.6 million of additional net proceeds received from sales of common units. This increase was partially offset by a $99.0 million increase in net repayments under our credit facility and an increase of $17.3 million in cash distributions to common limited partners and the general partner due mainly to increases in our common 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

- 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,		
	2006	**2005**	**2004**
Maintenance capital expenditures	$ 4,649	$ 1,922	$ 1,516
Expansion capital expenditures	79,182	50,576	8,527
Total	$ 83,831	$ 52,498	$ 10,043

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. As of December 31, 2006, we are committed to expend approximately $34.8 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Expansion capital expenditures increased to $50.6 million for the year ended December 31, 2005 compared with $8.5 million for the prior year due principally to expansions of the Velma and Elk City gathering systems and processing facilities to accommodate new wells drilled in our service areas. Expansion capital expenditures for our Mid-Continent region also include approximately $12.3 million of costs incurred related to the construction of the Sweetwater gas plant. In addition, expansion capital expenditures increased due to compressor upgrades and gathering system expansions in the Appalachia region. Maintenance capital expenditures for the year ended December 31, 2005 remained relatively consistent compared with the prior year period.

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% of the aggregate amount of cash being distributed. The general partner's incentive distributions declared during the year ended December 31, 2006 were $14.9 million.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2006 (in thousands):

		Payments Due By Period			
		Less than	1 3	4 5	After 5
Contractual cash obligations:	**Total**	**1 Year**	**Years**	**Years**	**Years**
Total debt [(1)]	$ 324,083	$ 71	$ 35	$ 38,000	$ 285,977
Operating leases	6,396	3,669	2,602	125	
Total contractual cash obligations	$ 330,479	$ 3,740	$ 2,637	$ 38,125	$ 285,977

(1) Not included in the table above are estimated interest payments calculated at the rates in effect at December 31, 2006: Less than one year $26.0 million; 1 to 3 years $52.1 million; 4 to 5 years $50.6 million; and after 5 years $91.9 million.

		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	$ 8,050	$ 8,025	$ 25	$	$
Other commercial commitments	34,844	34,844			
Total commercial commitments	$ 42,894	$ 42,869	$ 25	$	$

Other commercial commitments relate to commitments to purchase compressors which we had been leasing and for expenditures for pipeline extensions.

Common Equity Offerings

In May 2006, we sold 500,000 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 2,700,000 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 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 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 2,300,000 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.

In July 2004, we sold 2,100,000 common units in a public offering for total gross proceeds of $73.0 million. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $67.9 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale primarily to repay a portion of the amounts due under our credit facility and to redeem preferred units for $20.4 million, which were issued in connection with the acquisition of Spectrum in July 2004.

In April 2004, we sold 750,000 common units in a public offering for total gross proceeds of $27.0 million. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $25.2 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale primarily 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 million. As of December 31, 2006, $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, 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 Partners for $10.0 million on May 19, 2006, pursuant to our right to require Sunlight Capital Partners to purchase such additional units under the agreement with Sunlight. The preferred units are entitled to receive dividends of 6.5% per annum commencing on March 13, 2007, which will accrue and be paid quarterly on the same date as the distribution payment date for our common units. The preferred units are convertible, at the holder s option, into common units commencing on the date immediately following the first record date after March 13, 2007 at a conversion price equal to the lesser of $41.00 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. We have filed a registration statement to cover the resale of the common units underlying the preferred units. 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. The preferred units are reflected on our consolidated balance sheet as preferred equity within Partners Capital. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within Partners Capital on our 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 our net income in determining net income attributable to common unitholders and the general partner.

Credit Facility

We have a $225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears 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, 2006 was 7.6%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $8.1 million was outstanding at December 31, 2006. 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 wholly-owned subsidiaries, and by the guaranty of each of our wholly-owned subsidiaries. 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, 2006.

The events which constitute an event of default 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 senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA 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 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of December 31, 2006, our ratio of senior secured debt to EBITDA was 0.6 to 1.0, our funded debt ratio was 4.0 to 1.0 and our interest coverage ratio was 3.6 to 1.0.

We are unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

Senior Notes

In December 2005, we and our subsidiary, Atlas Pipeline Finance Corp. (APFC), issued $250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $243.1 million, after underwriting commissions and other transaction costs. In May 2006, we and APFC issued an additional $35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. 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 on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated 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 the credit facility.

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 our assets. We are in compliance with these covenants as of December 31, 2006.

In connection with a Senior Notes registration rights agreement entered into by us, we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes by April 19, 2006, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission by July 18, 2006, and (c) cause the exchange offer to be consummated by August 17, 2006. If we did not meet the aforementioned deadlines, the Senior Notes would be subject to additional interest, up to 1% per annum, until such time that the deadlines had been met. On April 19, 2006, we filed an exchange offer registration statement for the Senior Notes with the Securities and Exchange Commission, which was declared effective on July 11, 2006. The exchange offer was consummated on August 17, 2006, thereby fulfilling all of the requirements of the Senior Notes registration rights agreement by the specified dates.

NOARK Notes

On May 2, 2006, we acquired the remaining 25% 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, allocated severally 100% to Southwestern. In connection with the acquisition of the 25% 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.

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 believe our estimates are reasonable, actual results could differ from those estimates. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Key estimates used by our management include estimates used to record revenue and expense accruals, depreciation and amortization, asset impairment and fair values 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 that 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. Actual results could differ from those estimates.

Receivables

In evaluating the realizability of accounts receivable, we perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer s current creditworthiness, as determined by our review of the customers credit information. We extend credit on an unsecured basis to many of our energy customers. At December 31, 2006 and 2005, no allowance was recorded for uncollectible accounts receivable impairment.

Revenue Recognition

Revenue in the Appalachian segment is recognized at the time the natural gas is transported through the 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 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 is determined primarily by 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 natural gas liquids (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 regulated transmission pipeline is recognized at the time the transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. The majority of the revenue associated with our gathering and processing operations are based on percentage-of-proceeds (POP) and fixed-fee contracts. Under our POP purchasing arrangements, we purchase natural gas at the wellhead, process the natural gas by extracting NGLs and removing impurities, and sell the residue gas and NGLs at market-based prices, remitting to producers a contractually-determined percentage of the sale proceeds.

We accrue unbilled revenue due to timing differences between the delivery of natural gas, NGLs and oil 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). We had unbilled revenue at December 31, 2006 and 2005 of $20.2 million and $48.4 million, respectively, included in accounts receivable and accounts receivable-affiliates within our consolidated balance sheets.

Intangible Assets

We recorded intangible assets with finite lives in connection with certain consummated acquisitions (see Note 8 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). The following table reflects the components of intangible assets being amortized at December 31, 2006 and 2005 (in thousands):

	December 31,		Estimated Useful Lives
	2006	2005	In Years
Gross Carrying Amount:			
Customer contracts	$ 12,390	$ 23,990	8
Customer relationships	17,260	32,960	20
	$ 29,650	$ 56,950	
Accumulated Amortization:			
Customer contracts	$ (2,646)	$ (1,339)	
Customer relationships	(1,474)	(742)	
	$ (4,120)	$ (2,081)	
Net Carrying Amount:			
Customer contracts	$ 9,744	$ 22,651	
Customer relationships	15,786	32,218	
	$ 25,530	$ 54,869	

Certain amounts included within the intangible asset categories at December 31, 2005 were based upon a preliminary purchase price allocation for NOARK. During 2006, we adjusted the preliminary purchase price allocation 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 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. Amortization expense on intangible assets was $2.0 million and $2.1 million for the years ended December 31, 2006 and 2005, respectively. There was no amortization expense on intangible assets recorded during the year ended December 31, 2004. Amortization expense related to intangible assets is estimated to be $2.4 million for each of the next five calendar years commencing in 2007.

Goodwill

At December 31, 2006 and 2005, we had $63.4 million and $111.4 million, respectively, of 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). The changes in the carrying amount of goodwill for the years ended December 31, 2006, 2005 and 2004 were as follows (in thousands):

	Years Ended December 31,		
	2006	2005	2004
Balance, beginning of year	$ 111,446	$ 2,305	$ 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		
Reduction in minority interest deficit acquired	(118)	(1,083)	
Purchase price allocation adjustment NOARK	(78,082)		
Impairment losses			

Balance, end of year	$ 63,441	$ 111,446	$ 2,305

During 2006, we adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to goodwill based upon the preliminary findings of an independent valuation firm and allocated 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, 2006 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 income 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 pay 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 .

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 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 in our consolidated statements of income.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive loss and reclassify them to natural gas and liquids revenue within the consolidated statements of income 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 in the consolidated statements of income as they occur. At December 31, 2006 and 2005, we reflected net derivative liabilities on our consolidated balance sheets of $20.1 million and $30.4 million, respectively. Of the $22.1 million of net loss in accumulated other comprehensive loss at December 31, 2006, if the fair values of the instruments remain at current market values, we will reclassify $12.0 million of losses to natural gas and liquids revenue in the consolidated statements of income over the next twelve month period as these contracts expire, and $10.1 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within other income in the consolidated statements of income while the hedge contract is open and may increase or decrease until settlement of the contract. We recognized losses of $13.9 million, $11.1 million and $2,000 for the years ended December 31, 2006, 2005 and 2004, respectively, within natural gas and liquids revenue in the consolidated statements of income related to the settlement of qualifying hedge instruments. We recognized gains of $4.2 million and $1.5 million within other income in our consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the year ended December 31, 2006. We recognized a gain of $1.6 million and a loss of $0.3 million for the years ended December 31, 2005 and 2004, respectively, within other income in our consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only.

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 revenue.

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.

New Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159). SFAS 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. The Statement will be effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. The Statement offers various options in electing to apply the provisions of this Statement, and at this time we have not made any decisions in its application to our financial position or results of operations. We are currently evaluating whether SFAS 159 will have an impact on our financial position and 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. We are currently evaluating whether SFAS No. 157 will have an impact on our financial position and 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 our consolidated financial position or results of operations for the year ended December 31, 2006.

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, 2006. Only the potential impact of hypothetical assumptions are analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At December 31, 2006, we had a $225.0 million revolving credit facility ($38.0 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. The weighted average interest rate for these borrowings was 7.6% at December 31, 2006. Holding all other variables constant, a 1% change in interest rates would change interest expense by $0.4 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities 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. Based on our current portfolio of natural gas supply contracts, we have long condensate, NGL, and natural gas positions. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our consolidated income for the year ending December 31, 2007 of approximately $5.3 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.

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 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 in our consolidated statements of income.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive loss and reclassify them to natural gas and liquids revenue within the consolidated statements of income 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 in our consolidated statements of income as they occur. At December 31, 2006 and 2005, we reflected net derivative liabilities on our consolidated balance sheets of $20.1 million and $30.4 million, respectively. Of the $22.1 million of net loss in accumulated other comprehensive loss at December 31, 2006, if the fair values of the instruments remain at current market values, we will reclassify $12.0 million of losses to natural gas and liquids revenue in our consolidated statements of income over the next twelve month period as these contracts expire, and $10.1 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within other income in our consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. We recognized losses of $13.9 million, $11.1 million and $2,000 for the years ended December 31, 2006, 2005 and 2004, respectively, within natural gas and liquids revenue in our consolidated statements of income related to the settlement of qualifying hedge instruments. We recognized gains of $4.2 million and $1.5 million within other income in our consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the year ended December 31, 2006. We recognized a gain of $1.6 million and a loss of $0.3 million for the years ended December 31, 2005 and 2004, respectively, within other income in our consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only.

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 the Partnership s consolidated statements of income.

As of December 31, 2006, we had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Asset/(Liability)(1) (in thousands)
2007	84,924,000	$ 0.849	$ 3,058
2008	33,012,000	0.697	(3,996)
2009	8,568,000	0.746	(795)
			$ (1,733)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	CrudeVolume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(2) (in thousands)	Option Type
2008	720,000	40,219,000	$ 60.00	$ 2,950	Puts purchased
2008	720,000	40,219,000	84.00	(1,538)	Calls sold
2009	720,000	40,219,000	60.00	3,604	Puts purchased
2009	720,000	40,219,000	81.00	(2,349)	Calls sold
				$ 2,667	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Asset/(Liability)(2) (in thousands)
2007	1,080,000	$ 7.255	$ 313
2008	240,000	7.270	(216)
2009	480,000	8.000	78
			$ 175

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes	Average	Fair Value

		Fixed Price	Asset[2]
	(mmbtu)[3]	(per mmbtu)[3]	(in thousands)
2007	1,080,000	$ (0.535)	$ 420
2008	240,000	(0.555)	150
2009	480,000	(0.540)	41
			$ 611

Natural Gas Purchases

		Average	Fair Value
	Volumes	Fixed Price	Liability[2]
Production Period Ended December 31,	(mmbtu)[3]	(per mmbtu)[3]	(in thousands)
2007	6,960,000	$ 8.855[4]	$ (15,374)
2008	3,336,000	8.872[5]	(3,442)
2009	2,400,000	8.450	(1,470)
			$ (20,286)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)[3]	Average Fixed Price (per mmbtu)[3]	Fair Value Liability[2] (in thousands)
2007	6,960,000	$ (0.903)	$ (55)
2008	3,336,000	(1.042)	(63)
2009	2,400,000	(0.600)	(59)
			$ (177)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[2] (in thousands)
2007	77,900	$ 56.175	$ (670)
2008	65,400	59.424	(526)
2009	33,000	62.700	(148)
			$ (1,344)

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
2007	13,200	60.000	33	Puts purchased
2007	13,200	73.380	(26)	Calls sold
2008	17,400	60.000	71	Puts purchased
2008	17,400	72.784	(85)	Calls sold
2009	30,000	60.000	147	Puts purchased
2009	30,000	71.250	(178)	Calls sold
			$ (38)	
		Total net liability	$ (20,125)	

(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 our premium received from the sale of an option for us to sell 4,800,000 mmbtu of natural gas at an average price of $15.25 per mmbtu for the year ended December 31, 2007, partially offset by our premium paid from the purchase of an option to purchase 1,200,000 mmbtu of natural gas at $26.00 per mmbtu.

(5)

Includes our premium received from the sale of an option for us to sell 936,000 mmbtu of natural gas for the year ended December 31, 2008 at $15.50 per mmbtu.

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, 2006 and 2005, and the related consolidated statements of income and comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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, 2006, 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 March 9, 2007 expressed an unqualified opinion on management s assessment of and an adverse opinion on the effective operation of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Cleveland, Ohio
March 9, 2007

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,795	$ 34,237
Accounts receivable affiliates	7,601	4,649
Accounts receivable	51,192	57,528
Current portion of derivative asset	5,437	11,388
Prepaid expenses and other	10,444	2,454
Total current assets	76,469	110,256
Property, plant and equipment, net	607,097	445,066
Long-term derivative asset	305	4,388
Intangible assets, net	25,530	54,869
Goodwill	63,441	111,446
Other assets, net	14,042	16,701
	$ 786,884	$ 742,726
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 71	$ 1,263
Accounts payable	18,624	15,609
Accrued liabilities	6,410	16,064
Current portion of derivative liability	17,362	23,796
Accrued producer liabilities	32,766	36,712
Total current liabilities	75,233	93,444
Long-term derivative liability	8,505	22,410
Long-term debt, less current portion	324,012	297,362
Commitments and contingencies		
Partners capital:		
Preferred limited partner s interest	39,381	
Common limited partners interests	350,805	349,491
General partner s interest	11,034	10,094
Accumulated other comprehensive loss	(22,086)	(30,075)
Total partners capital	379,134	329,510
	$ 786,884	$ 742,726

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per unit data)

	Years Ended December 31, 2006	2005	2004
Revenue:			
Natural gas and liquids	$ 391,356	$ 338,672	$ 72,364
Transportation and compression affiliates	30,189	24,346	18,724
Transportation and compression third parties	30,735	5,963	76
Other income	12,412	2,519	127
Total revenue and other income	464,692	371,500	91,291
Costs and expenses:			
Natural gas and liquids	334,299	288,180	58,707
Plant operating	15,722	10,557	2,032
Transportation and compression	12,013	4,053	2,260
General and administrative	18,990	11,825	3,562
Compensation reimbursement affiliates	2,319	1,783	1,081
Depreciation and amortization	22,994	13,954	4,471
Interest	24,572	14,175	2,301
Minority interest in NOARK	118	1,083	
Other		138	(1,457)
Total costs and expenses	431,027	345,748	72,957
Net income	33,665	25,752	18,334
Preferred unit imputed dividend cost	(1,898)		
Premium on preferred unit redemption			(400)
Net income attributable to common limited partners and the general partner	$ 31,767	$ 25,752	$ 17,934
Allocation of net income attributable to common limited partners and the general partner:			
Common limited partners interest	$ 16,558	$ 16,355	$ 14,864
General partner s interest	15,209	9,397	3,070
Net income attributable to common limited partners and the general partner	$ 31,767	$ 25,752	$ 17,934
Net income attributable to common limited partners per unit:			
Basic	$ 1.29	$ 1.86	$ 2.53
Diluted	$ 1.27	$ 1.84	$ 2.53
Weighted average common limited partner units outstanding:			
Basic	12,884	8,808	5,866
Diluted	13,053	8,872	5,870

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31, 2006	2005	2004
Net income	$ 33,665	$ 25,752	$ 18,334
Preferred unit imputed dividend cost	(1,898)		
Premium on preferred unit redemption			(400)
Net income attributable to common limited partners and the general partner	31,767	25,752	17,934
Other comprehensive income/(loss):			
Change in fair value of derivative instruments accounted for as hedges	(5,956)	(39,882)	(1,320)
Add: adjustment for realized losses in net income	13,945	11,125	2
	7,989	(28,757)	(1,318)
Comprehensive income (loss)	$ 39,756	$ (3,005)	$ 16,616

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Limited Partner Units			Preferred Limited Partner	Common Limited Partners	Subordinated Limited Partner	General Partner	Accumulated Other Comprehensive Income/(Loss)	Total Partners Capital
	Preferred	Common	Subordinated						
Balance at January 1, 2004		2,713,659	1,641,026	$	$ 43,551	$ 354	$ 340	$	$ 44,245
Issuance of common units in public offering		2,850,000			93,119				93,119
General partner capital contributions							1,994		1,994
Distributions to partners					(7,732)	(3,200)	(1,871)		(12,803)
Distribution payable					(4,006)	(1,181)	(1,280)		(6,467)
Other comprehensive loss								(1,318)	(1,318)
Net income					10,941	3,923	3,070		17,934
Balance at December 31, 2004		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
							1,206		1,206

General partner capital contribution								
Unissued common units under incentive plans				6,315				6,315
Issuance of units under incentive plans		31,152						
Distributions paid to common limited partners and the general partner				(43,194)		(15,523)		(58,717)
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

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, 2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 33,665	$ 25,752	$ 17,934
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	22,994	13,954	4,471
Non-cash gain on derivative value	(2,316)	(954)	(210)
Non-cash compensation expense	6,315	4,672	700
Gain on asset sales and dispositions	(2,719)		
Gain on insurance claim settlement	(2,921)		
Amortization of deferred finance costs	2,298	2,140	400
Minority interest in NOARK	118	1,083	
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable and prepaid expenses and other	944	(27,823)	4,361
Accounts payable and accrued liabilities	(10,282)	35,246	(3,264)
Accounts payable and accrued receivable affiliates c	(2,952)	(3,153)	801
Net cash provided by operating activities	45,144	50,917	25,193
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash paid for acquisitions	(30,000)	(358,831)	(141,626)
Capital expenditures	(83,831)	(52,498)	(10,043)
Proceeds from insurance claim settlement	1,522		
Proceeds from sales of assets	7,540		
Other	155	325	(128)
Net cash used in investing activities	(104,614)	(411,004)	(151,797)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from issuance of debt	36,582	243,102	
Repayment of debt	(39,019)	(677)	
Borrowings under credit facility	81,000	463,500	110,000
Repayments under credit facility	(52,500)	(508,250)	(55,750)
Net proceeds from issuance of common limited partner units	19,704	212,700	93,119
Net proceeds from issuance of preferred limited partner units	39,881		
General partner capital contributions	1,206	4,684	1,994
Distributions paid to common limited partners and the general partner	(58,717)	(33,140)	(15,876)
Net proceeds from sale of preferred units			20,000
Redemption of preferred units			(20,000)
Other	(1,109)	(5,809)	(3,747)
Net cash provided by financing activities	27,028	376,110	129,740
Net change in cash and cash equivalents	(32,442)	16,023	3,136
Cash and cash equivalents, beginning of year	34,237	18,214	15,078
Cash and cash equivalents, end of year	$ 1,795	$ 34,237	$ 18,214

See accompanying notes to consolidated financial statements

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 1,641,026 limited partner units in the Partnership which have not been registered with the Securities and Exchange Commission and, therefore, their resale in the public market is subject to restrictions under the Securities Act. At December 31, 2006, the Partnership had 13,080,418 common limited partnership units, including 1,641,026 unregistered common units held by the General Partner, and 40,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4).

On July 26, 2006, Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS), contributed its ownership interests in the General Partner to Atlas Pipeline Holdings, L.P. (AHD NYSE: AHD), a then wholly-owned subsidiary of Atlas America. Concurrent with this transaction, AHD issued 3,600,000 common units, representing a 17.1% ownership interest, in an initial public offering at a price of $23.00 per unit. Net proceeds from this offering were distributed to Atlas America.

On December 18, 2006, Atlas America, which owns an 82.9% ownership interest in AHD, the parent of the Partnership s General Partner, contributed its ownership interests in its natural gas and oil development and production subsidiaries to Atlas Energy Resources, LLC and subsidiaries (Atlas Energy NYSE: ATN), a then wholly-owned subsidiary of Atlas America. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a 19.4% ownership interest, in an initial public offering at a price of $21.00 per unit. Net proceeds from this offering were distributed to Atlas America. 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 partial settlement of the insurance proceeds related to this incident of $1.5 million from its insurance providers and reached a final settlement for an additional $2.6 million of insurance proceeds to be received during the first quarter of 2007. At December 31, 2006, the Partnership has recorded this additional $2.6 million in prepaid expenses and other within its consolidated balance sheet and interest income and other within its consolidated statements of income for the insurance proceeds settlement amount, which was received in February, 2007.

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.

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, APL consolidates 100% of NOARK s financial statements. The minority interest expense in NOARK reflected on the Partnership s consolidated statements of income 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. Actual results could differ from those estimates.

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, 2006 and 2005, the Partnership recorded no allowance for uncollectible accounts receivable.

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 8.1% and 6.6% for the years ended December 31, 2006 and 2005, respectively, and the amount of interest capitalized was $2.6 million and $0.1 million for the years ended December 31, 2006 and 2005, respectively. There was no interest capitalized for the year ended December 31, 2004.

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 income unless specific hedge accounting criteria are met.

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, 2006 and 2005 (in thousands):

	December 31,		Estimated Useful Lives In Years
	2006	**2005**	
Gross Carrying Amount:			
Customer contracts	$ 12,390	$ 23,990	8
Customer relationships	17,260	32,960	20
	$ 29,650	$ 56,950	
Accumulated Amortization:			
Customer contracts	$ (2,646)	$ (1,339)	
Customer relationships	(1,474)	(742)	
	$ (4,120)	$ (2,081)	
Net Carrying Amount:			
Customer contracts	$ 9,744	$ 22,651	
Customer relationships	15,786	32,218	

	$ 25,530	$ 54,869

Certain amounts included within the intangible asset categories at December 31, 2005 were based upon a preliminary purchase price allocation for NOARK. During 2006, the Partnership adjusted the preliminary purchase price allocation and reduced the estimated amount allocated to customer contracts and customer relationships based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6).

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 $2.0 million and $2.1 million for the years ended December 31, 2006 and 2005, respectively. There was no amortization expense on intangible assets recorded during the year ended December 31, 2004. Amortization expense related to intangible assets is estimated to be $2.4 million for each of the next five calendar years commencing in 2007.

Goodwill

At December 31, 2006 and 2005, the Partnership had $63.4 million and $111.4 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, 2006, 2005 and 2004 were as follows (in thousands):

	Years Ended December 31,		
	2006	**2005**	**2004**
Balance, beginning of year	$ 111,446	$ 2,305	$ 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		
Reduction in minority interest deficit acquired	(118)	(1,083)	
Purchase price allocation adjustment NOARK	(78,082)		
Impairment losses			
Balance, end of year	$ 63,441	$ 111,446	$ 2,305

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 (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6). The Partnership tests its 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 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, 2006 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 income for the period in which the impairment is indicated.

Federal Income Taxes

The Partnership is a limited partnership. As a result, the Partnership s income for federal income tax purposes is reportable on the tax returns of the individual partners. Accordingly, no recognition has been given to income taxes in the accompanying consolidated financial statements of the Partnership.

Net income, for financial statement purposes, may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. These different allocations can and usually will result in significantly different tax capital account balances in comparison to the capital accounts per the consolidated financial statements.

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 Per Common Unit

Basic net income attributable to common limited partners per unit is computed by dividing net income 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 is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5). Diluted net income attributable to common limited partners per unit is calculated by dividing net income 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. Phantom units consist of common units issuable under the terms of the Partnership s Long-Term Incentive Plan and Incentive Compensation Agreements (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 attributable to common limited partners per unit with those used to compute diluted net income attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2006	**2005**	**2004**
Weighted average common limited partner units - basic	12,884	8,808	5,866
Add effect of dilutive unit incentive awards	169	64	4
Weighted average common limited partner units - diluted	13,053	8,872	5,870

For 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 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 years ended December 31, 2005 and 2004.

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, 2006 and 2005, the Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two business segments: natural gas transmission and gathering located in the Appalachia Basin area (Appalachia) and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent). Appalachia revenues are, for the most part, based on contractual arrangements with Atlas America and its affiliates. Mid-Continent revenues are, for the most part, derived from the sale of residue gas and NGLs to purchasers at the tailgate of the processing plants.

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 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 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 regulated transmission pipeline is recognized at the time the transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. The majority of the revenue associated with the Partnership s gathering and processing operations is based on percentage-of-proceeds (POP) and fixed-fee contracts. Under its POP purchasing arrangements, the Partnership purchases natural gas at the wellhead, processes the natural gas by extracting NGLs and removing impurities and sells the residue gas and NGLs at market-based prices, remitting to producers a contractually-determined percentage of the sale proceeds.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and oil and the receipt of a delivery statement. These revenues are 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, 2006 and 2005 of $20.2 million and $48.4 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 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, are referred to as other comprehensive income (loss) and for the Partnership only include changes in the fair value of unsettled hedge contracts.

New Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159). SFAS 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. The Statement will be effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. The Statement offers various options in electing to apply the provisions of this Statement, and at this time we have not made any decisions in its application to the Partnership s financial position or results of operations. The Partnership is currently evaluating whether SFAS 159 will have an impact on its financial position and 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. The Partnership is currently evaluating whether SFAS No. 157 will have an impact on its financial position and 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. The Partnership adopted SAB 108 as of December 31, 2006 as required and it did not have an impact on its consolidated financial position as of December 31, 2006 or its results of operations for the year ended December 31, 2006.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

On May 12, 2006, the Partnership sold 500,000 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 2,700,000 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 2,300,000 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.

In July 2004, the Partnership sold 2,100,000 common units in a public offering for total gross proceeds of $73.0 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $67.9 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale primarily to repay a portion of the amounts due under its credit facility and to redeem preferred units for $20.4 million (see Note 8), which were issued in connection with the acquisition of Spectrum Field Services, Inc. in July 2004.

In April 2004, the Partnership sold 750,000 common units in a public offering for total gross proceeds of $27.0 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $25.2 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale primarily 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, 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 Partners for $10.0 million on May 19, 2006, pursuant to the Partnership s right under the agreement to require Sunlight Capital Partners to purchase such additional units. Commencing on March 13, 2007, the preferred units will be entitled to receive dividends of 6.5% per annum, which will accrue and be paid quarterly on the same date as the distribution payment date for the

Partnership s common units. The preferred units are convertible, at the holder s option, into the Partnership s common units commencing on the date immediately following the first record date after March 13, 2007 at a conversion price equal to the lesser of $41.00 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 Partnership has filed a registration statement to cover the resale of the common units underlying the preferred units. 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.

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 recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost is the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006. The total imputed dividend cost of $2.4 million on the preferred units, including the $0.5 million of imputed dividend cost related to the additional 10,000 units, was allotted to common limited partners and the general partner s interests within partner s capital on the consolidated balance sheet and is based upon the present value of the net proceeds received using the 6.5% stated yield commencing March 13, 2007. The imputed dividend cost is amortized for the period from the respective issuances of the preferred units through March 13, 2007, and the amortization is presented as a reduction of net income to determine net income attributable to common limited partners and the general partner. Amortization of the imputed dividend cost for the year end December 31, 2006 was $1.9 million. 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 in determining net income attributable to common unitholders and the general partner.

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, 2004 through December 31, 2006 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)
May 7, 2004	March 31, 2004	$0.63	$2,743	$374
August 6, 2004	June 30, 2004	$0.63	$3,216	$438
November 5, 2004	September 30, 2004	$0.69	$4,971	$1,059
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

On January 24, 2007, the Partnership declared a cash distribution of $0.86 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2006. The $15.4 million distribution, including $4.2 million to the General Partner, was paid on February 14, 2007 to unitholders of record at the close of business on February 7, 2007.

At December 31, 2004, the General Partner held 1,641,026 subordinated limited partner units in the Partnership. In January 2005, these subordinated units were converted to common units as the Partnership met applicable tests under the terms of the partnership agreement. While the General Partner s rights as the holder of the subordinated units are no longer subordinated to the rights of the Partnership s common unitholders, these units have not been registered with the Securities and Exchange Commission and, therefore, their resale in the public market is subject to restrictions under the Securities Act.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	December 31,		Estimated Useful Lives
	2006	**2005**	**in Years**
Pipelines, processing and compression facilities	$ 611,575	$ 443,729	15 40
Rights of way	30,401	19,252	20 40
Buildings	3,800	3,350	40
Furniture and equipment	3,288	1,525	3 7
Other	2,081	889	3 10
	651,145	468,745	
Less accumulated depreciation	(44,048)	(23,679)	
	$ 607,097	$ 445,066	

On May 2, 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. At December 31, 2005, the portion of the purchase price allocated to property, plant and equipment for NOARK was included within pipelines, processing and compression facilities.

NOTE 7 OTHER ASSETS

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

	December 31,	
	2006	**2005**
Deferred finance costs, net of accumulated amortization of $3,972 and $1,636 at December 31, 2006 and 2005, respectively	$ 12,530	$ 15,034
Security deposits	1,415	1,599
Other	97	68
	$ 14,042	$ 16,701

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 10).

NOTE 8 ACQUISITIONS

NOARK

On May 2, 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, Business Combinations (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.

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.

Spectrum

In July 2004, the Partnership acquired Spectrum Field Services, Inc. (Spectrum or Velma), for approximately $141.6 million, including transaction costs and the payment of taxes due as a result of the transaction. Spectrum s principal assets included 1,900 miles of natural gas pipelines and a natural gas processing facility in Velma, 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):

Cash and cash equivalents	$ 803
Accounts receivable	18,505
Prepaid expenses	649
Property, plant and equipment	139,464
Other long-term assets	1,054
Total assets acquired	160,475
Accounts payable and other liabilities	(18,836)
Net assets acquired	141,639
Less: Cash and cash equivalents acquired	(803)
Net cash paid for acquisition	$ 140,836

The results of Spectrum s operations are included within the Partnership s consolidated financial statements from its date of acquisition. In connection with financing the acquisition of Spectrum, the Partnership issued preferred units to Resource America, Inc., an affiliate of Atlas America at the date of the transaction, and Atlas America for $20.0 million. These preferred units were subsequently redeemed for $20.4 million, including a $0.4 million premium, with the net proceeds from the Partnership s July 2004 equity offering (see Note 3).

The following data presents pro forma revenue and net income for the Partnership as if the acquisitions discussed above, the equity offerings in May 2006, November 2005 and June 2005 (see Note 3), the May 2006 and December 2005 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, 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,		
	2006	2005	2004
Total revenue and other income	$ 464,692	$ 469,867	$ 372,113
Net income	$ 33,853	$ 21,148	$ 12,554
Net income attributable to common limited partners and the general partner	$ 31,676	$ 19,275	$ 10,281
Net income attributable to common limited partners per unit:			
Basic	$ 1.26	$ 0.77	$ 0.57
Diluted	$ 1.24	$ 0.76	$ 0.56

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 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, 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 in its consolidated statements of income.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. 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 income 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 in its consolidated statements of income as they occur. At December 31, 2006 and 2005, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $20.1 million and $30.4 million, respectively. Of the $22.1 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at December 31, 2006, if the fair values of the instruments remain at current market values, the Partnership will reclassify $12.0 million of losses to natural gas and liquids revenue in its consolidated statements of income over the next twelve month period as these contracts expire, and $10.1 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within other income in the Partnership s consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. The Partnership recognized losses of $13.9 million, $11.1 million and $2,000 for the years ended December 31, 2006, 2005 and 2004, respectively, within natural gas and liquids revenue in its consolidated statements of income related to the settlement of qualifying hedge instruments. The Partnership recognized gains of $4.2 million and $1.5 million within other income in its consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the year ended December 31, 2006. The Partnership recognized a gain of $1.6 million and a loss of $0.3 million for the years ended December 31, 2005 and 2004, respectively, within other income in its consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only.

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 income.

As of December 31, 2006, the Partnership had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Asset/(Liability)(1) (in thousands)
2007	84,924,000	$ 0.849	$ 3,058
2008	33,012,000	0.697	(3,996)
2009	8,568,000	0.746	(795)
			$ (1,733)

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	720,000	40,219,000	$ 60.00	$ 2,950	Puts purchased
2008	720,000	40,219,000	84.00	(1,538)	Calls sold
2009	720,000	40,219,000	60.00	3,604	Puts purchased
2009	720,000	40,219,000	81.00	(2,349)	Calls sold
				$ 2,667	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu) (3)	Average Fixed Price (per mmbtu) (3)	Fair Value Asset/(Liability)(2) (in thousands)
2007	1,080,000	$ 7.255	$ 313
2008	240,000	7.270	(216)
2009	480,000	8.000	78
			$ 175

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Asset(2) (in thousands)
2007	1,080,000	$ (0.535)	$ 420
2008	240,000	(0.555)	150
2009	480,000	(0.540)	41
			$ 611

Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Liability(2) (in thousands)
2007	6,960,000	$ 8.855(4)	$ (15,374)
2008	3,336,000	8.872(5)	(3,442)
2009	2,400,000	8.450	(1,470)
			$ (20,286)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Liability(2) (in thousands)
2007	6,960,000	$ (0.903)	$ (55)
2008	3,336,000	(1.042)	(63)
2009	2,400,000	(0.600)	(59)
			$ (177)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[2] (in thousands)
2007	77,900	$ 56.175	$ (670)
2008	65,400	59.424	(526)
2009	33,000	62.700	(148)
			$ (1,344)

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
2007	13,200	60.000	33	Puts purchased
2007	13,200	73.380	(26)	Calls sold
2008	17,400	60.000	71	Puts purchased
2008	17,400	72.784	(85)	Calls sold
2009	30,000	60.000	147	Puts purchased
2009	30,000	71.250	(178)	Calls sold
			$ (38)	
		Total net liability	$ (20,125)	

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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 4,800,000 mmbtu of natural gas at an average price of $15.25 per mmbtu for the year ended December 31, 2007, partially offset by its premium paid from its purchase of an option to purchase 1,200,000 mmbtu of natural gas at $26.00 per mmbtu.

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

NOTE 10 DEBT

Total debt consists of the following (in thousands):

	December 31, 2006	December 31, 2005
Revolving credit facility	$ 38,000	$ 9,500
Senior notes	285,977	250,000
NOARK notes		39,000
Other debt	106	125
Total debt	324,083	298,625
Less current maturities	(71)	(1,263)
Total long-term debt	$ 324,012	$ 297,362

Credit Facility

The Partnership has a $225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears 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 credit facility borrowings at December 31, 2006 was 7.6%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $8.1 million was outstanding at December 31, 2006. 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 wholly-owned subsidiaries, and by the guaranty of each of its wholly-owned subsidiaries. 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, 2006.

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 senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA 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 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of December 31, 2006, the Partnership s ratio of senior secured debt to EBITDA was 0.6 to 1.0, its funded debt ratio was 4.0 to 1.0 and its interest coverage ratio was 3.6 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

In December 2005, the Partnership and its subsidiary, Atlas Pipeline Finance Corp. (APFC), issued $250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $243.1 million, after underwriting commissions and other transaction costs. In May 2006, the Partnership and APFC issued an additional $35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. 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 on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated 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 the Credit Facility.

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, 2006.

In connection with a Senior Notes registration rights agreement entered into by the Partnership, it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes by April 19, 2006, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission by July 18, 2006, and (c) cause the exchange offer to be consummated by August 17, 2006. If the Partnership did not meet the aforementioned deadlines, the Senior Notes would be subject to additional interest, up to 1% per annum, until such time that the deadlines had been met. On April 19, 2006, the Partnership filed an exchange offer registration statement for the Senior Notes with the Securities and Exchange Commission, which was declared effective on July 11, 2006. The exchange offer was consummated on August 17, 2006, thereby fulfilling all of the requirements of the Senior Notes registration rights agreement by the specified dates.

NOARK Notes

On May 2, 2006, the Partnership acquired the remaining 25% 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 the Partnership s consolidated balance sheet, allocated severally 100% to Southwestern. In connection with the acquisition of the 25% 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 the Partnership nor NOARK have any further liability with respect to such notes.

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

Years Ended December 31:	
2007	$ 71
2008	35
2009	
2010	
2011	38,000
Thereafter	285,977
	$ 324,083

Cash payments for interest related to debt were $25.5 million, $9.2 million, and $2.1 million for the years ended December 31, 2006, 2005 and 2004, 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, 2006, 2005 and 2004 was $4.0 million, $2.0 million, and $0.8 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2006 is as follows (in thousands):

Years Ended December 31:	
2007	$ 3,669
2008	2,125
2009	477
2010	80
2011	45
Thereafter	
	$ 6,396

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, 2006, the Partnership is committed to expend approximately $34.8 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, 2006 and 2005, which consists principally of the Senior Notes, borrowings under the Credit Facility and the NOARK Notes, was $330.9 million and $295.3 million, respectively, compared with the carrying amount of $324.0 million and $297.4 million, respectively. The Senior Notes and the NOARK 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, 2006, the Mid-Continent segment had three customers that individually accounted for approximately 36%, 19% and 10% of the Partnership s consolidated total revenues, three customers that individually accounted for approximately 33%, 15% and 11% of the Partnership s consolidated total revenues for the year ended December 31, 2005, and two customers that individually accounted for approximately 34% and 25% of the Partnership s consolidated total revenues for the year ended December 31, 2004. Additionally, the Mid-Continent segment had one customer that accounted for 16% and two customers that individually accounted for 24% and 23% of the Partnership s consolidated accounts receivable at December 31, 2006 and 2005, 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, 2006, the Partnership and its subsidiaries had $2.5 million in deposits at banks, of which $2.0 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, 2006.

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, 2006, 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, 2006, 51,130 units will vest within the following twelve months. All units outstanding under the LTIP at December 31, 2006 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs were $0.4 million, $0.3 million and $0.1 million for the years ended December 31, 2006, 2005 and 2004, respectively. These amounts were recorded as reductions of Partners Capital on the consolidated balance sheet.

The Partnership has adopted 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 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 the LTIP, the Partnership has only granted phantom units with no exercise price and, as such, recognized compensation expense based upon the fair value of the Partnership s limited partner units. Since the Partnership has historically recognized compensation expense for its unit-based payments at their fair values, the adoption of SFAS No. 123(R) did not have a material impact on its consolidated financial statements.

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

	Years Ended December 31,		
	2006	**2005**	**2004**
Outstanding, beginning of year	110,128	58,329	
Granted[(1)]	82,091	67,399	59,175
Matured	(31,152)	(14,581)	
Forfeited	(2,000)	(1,019)	(846)
Outstanding, end of year	159,067	110,128	58,329
Non-cash compensation expense recognized (in thousands)	$ 2,030	$ 2,201	$ 700

(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 $45.45, $48.59 and $37.15 for awards granted for the years ended December 31, 2006, 2005 and 2004, respectively.

At December 31, 2006, the Partnership had approximately $4.3 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 is dependent upon the achievement of certain predetermined performance targets. These performance targets include the accomplishment of specific financial goals for the Partnership s Velma system through September 30, 2007 and the financial performance of other previous and future consummated acquisitions, including Elk City and NOARK, through December 31, 2008. The awards associated with the performance targets of the Velma system will vest on September 30, 2007, and awards associated with performance targets of other acquisitions will vest on December 31, 2008.

The Partnership recognized compensation expense of $4.3 million and $2.5 million for the years ended December 31, 2006 and 2005, respectively, related to the vesting of awards under these incentive compensation agreements. No compensation expense was recognized for these awards for the year ended December 31, 2004 as management determined that the achievement of these performance targets was not probable at that time. Based upon management s estimate of the probable outcome of the performance targets at December 31, 2006, 224,935 common unit awards are ultimately expected to be issued under these agreements. At December 31, 2006, the Partnership had approximately $3.2 million of unrecognized compensation expense related to the unvested portion of these awards based upon management s estimate of performance target achievement. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method.

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 $2.3 million, $1.8 million and $1.1 million for the years ended December 31, 2006, 2005 and 2004, respectively, for compensation and benefits related to their employees. For the years ended December 31, 2006, 2005 and 2004, direct reimbursements were $28.6 million, $24.8 million and $13.4 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 SETTLEMENT OF TERMINATED ALASKA PIPELINE ARBITRATION

In September 2003, the Partnership entered into an agreement with SEMCO Energy, Inc. (SEMCO) to purchase all of the stock of Alaska Pipeline. In order to complete the acquisition, the Partnership needed the approval of the Regulatory Commission of Alaska. The Regulatory Commission initially approved the transaction, but on June 4, 2004, it vacated its order of approval based upon a motion for clarification or reconsideration filed by SEMCO. On July 1, 2004, SEMCO sent the Partnership a notice purporting to terminate the transaction. The Partnership pursued its remedies under the acquisition agreement. In connection with the acquisition, subsequent termination and legal action, the Partnership incurred costs of approximately $4.0 million. On December 30, 2004, the Partnership entered into a settlement agreement with SEMCO settling all issues and matters related to SEMCO s termination of the sale of Alaska Pipeline to the Partnership and SEMCO paid the Partnership $5.5 million. The Partnership recognized a gain of $1.5 million for the year ended December 31, 2004 on this settlement which is shown as gain on arbitration settlement, net, on its consolidated statements of income.

NOTE 16 OPERATING SEGMENT INFORMATION

The Partnership has two operating 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 southern Oklahoma, northern Texas and Arkansas. 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 operating segments reflect the way the Partnership manages its operations.

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

	Years Ended December 31,		
	2006	2005	2004
Mid-Continent:			
Revenue			
Natural gas and liquids	$ 391,356	$ 338,672	$ 72,364
Transportation and compression - third parties	30,653	5,880	
Other income (loss)	11,804	2,138	(195)
Total revenues and other income	433,813	346,690	72,169
Costs and expenses			
Natural gas and liquids	334,299	288,180	58,707
Plant operating	15,722	10,557	2,032
Transportation and compression	7,067	952	
General and administrative	13,776	7,375	1,088
Minority interest in NOARK	118	1,083	
Depreciation and amortization	19,322	11,307	2,408
Total costs and expenses	390,304	319,454	64,235
Segment profit	$ 43,509	$ 27,236	$ 7,934

Appalachia:			
Revenue			
Transportation and compression affiliates	$ 30,189	$ 24,346	$ 18,724
Transportation and compression third parties	82	83	76
Other income	608	381	322
Total revenues and other income	30,879	24,810	19,122
Costs and expenses			
Transportation and compression	4,946	3,101	2,260
General and administrative	3,767	3,117	1,777
Depreciation and amortization	3,672	2,647	2,063
Total costs and expenses	12,385	8,865	6,100
Segment profit	$ 18,494	$ 15,945	$ 13,022
Reconciliation of segment profit to net income:			
Segment profit			
Mid-Continent	$ 43,509	$ 27,236	$ 7,934
Appalachia	18,494	15,945	13,022
Total segment profit	62,003	43,181	20,956
Corporate general and administrative expenses	(3,766)	(3,116)	(1,778)
Interest expense	(24,572)	(14,175)	(2,301)
Other		(138)	1,457
Net income	$ 33,665	$ 25,752	$ 18,334
Capital Expenditures:			
Mid-Continent	$ 65,416	$ 35,263	$ 3,858
Appalachia	18,415	17,235	6,185
	$ 83,831	$ 52,498	$ 10,043

	December 31, 2006	2005
Balance sheet		
Total assets:		
Mid-Continent	$ 730,791	$ 668,782
Appalachia	42,448	43,428
Corporate other	13,645	30,516
	$ 786,884	$ 742,726
Goodwill:		
Mid-Continent	$ 61,136	$ 109,141
Appalachia	2,305	2,305
	$ 63,441	$ 111,446

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

	Years Ended December 31, 2006	2005	2004
Natural gas and liquids:			
Natural gas	$ 196,182	$ 198,972	$ 39,163
NGLs	169,840	126,498	31,631
Condensate	6,678	5,417	589
Other [(1)]	18,656	7,785	981
Total	$ 391,356	$ 338,672	$ 72,364
Transportation and Compression:			
Affiliates	$ 30,189	$ 24,346	$ 18,724
Third parties	30,735	5,963	76
Total	$ 60,924	$ 30,309	$ 18,800

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

NOTE 17 QUARTERLY FINANCIAL DATA (Unaudited)

	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	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.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
	(in thousands, except per unit data)			
Year ended December 31, 2005:				
Revenue and other income	$ 136,379	$ 102,645	$ 85,199	$ 47,277
Costs and expenses	125,520	95,591	81,610	43,027
Net income attributable to partners	10,859	7,054	3,589	4,250
Basic net income per common limited partner unit	0.70	0.48	0.20	0.39
Diluted net income per common limited partner unit	0.69	0.48	0.20	0.39

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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 principal executive officer and principal 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.

Our management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report which is included herein. Based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting as of December 31, 2006 was ineffective because it identified a material weakness with regard to our accounting for certain derivative instruments in accordance with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Specifically, we entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge our exposure to movements in commodity prices that were not appropriately valued within our consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, we did not record a fair value for the time-value component of the derivative instruments. All of our other derivative instruments that were in effect during 2006 have been appropriately recorded within our consolidated financial statements. This material weakness resulted in the amendment of our Form 10-Q as of September 30, 2006.

Subsequent to our discovery of the material weakness discussed above, in early 2007 we took steps to remediate the material weakness, including reviewing the accounting requirements necessary for compliance with SFAS No. 133 and establishing additional review procedures of accounting for derivative transactions by senior personnel within our organization. We believe these actions will strengthen our internal control over financial reporting and address the material weakness identified.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Atlas Pipeline Partners, L.P. (the Partnership) (a Delaware limited partnership) did not maintain effective internal control over financial reporting as of December 31, 2006, because of the effect of a material weakness identified in management s assessment related to the effectiveness of internal controls pertaining to the accounting for certain financial hedge instruments, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provide a reasonable basis for our opinions.

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 the 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.

A material weakness is a control deficiency, or combination of control deficiencies, that result in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management s assessment:

A material weakness with regard to the Partnership s accounting for certain derivative instruments in accordance with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Specifically, the Partnership entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge its exposure movements in commodity prices that were not appropriately valued within its consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, the Partnership did not record a fair value for the time-value component of the derivative instruments.

This material weakness was considered in determining the nature, timing, and extent of the audit tests applied in our audit of the 2006 financial statements, and this report does not affect our report dated March 9, 2007*,* which expressed an unqualified opinion on those financial statements.

In our opinion, management s assessment that Atlas Pipeline Partners, L.P. did not maintain effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control Integrated Framework issued by COSO. Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Atlas Pipeline Partners, L.P. has not maintained effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by COSO.

We express no opinion on the steps taken by management in early 2007 to remediate the identified material weaknesses.

/s/ GRANT THORNTON LLP

Cleveland, Ohio
March 9, 2007

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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	68	Chairman of the Managing Board and Chief Executive Officer	1999
Jonathan Z. Cohen	36	Vice Chairman of the Managing Board	1999
Michael L. Staines	57	President, Chief Operating Officer and Managing Board Member	1999
Matthew A. Jones	45	Chief Financial Officer	2005
Robert R. Firth	52	President & Chief Executive Officer of Atlas Pipeline Mid-Continent, LLC	2004
Tony C. Banks	52	Managing Board Member	1999
Curtis D. Clifford	64	Managing Board Member	2004
Gayle P.W. Jackson	60	Managing Board Member	2005
Martin Rudolph	60	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 formation 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) since 1998 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 formation 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 was its Vice Chairman from 2003 until December 2006. Mr. Cohen is a son of Edward E. Cohen.

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 for FirstEnergy Corporation, a public utility, since March 2007. From December 2005 to February 2007, Mr. Banks was Vice President of Business Development. 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. 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, which was an energy technology subsidiary of Atlas America until 2002. 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.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Mr. Clifford has 40 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 Central and Eastern Europe, Latin America and Asia. 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.

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, 49, 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, 30, has served as our general partner s Vice President of Corporate Development and as Vice President of Corporate Development of Atlas America since December 2004. Mr. Herz has been the Vice President of Corporate Development of Atlas Holdings GP since its formation. Mr. Herz has been an employee of Atlas America since January 2004. Mr. Herz was an Associate Investment Banker with Banc of America Securities Energy Group from 2002 to 2003 and an Analyst in the Energy Group from 1999 to 2002.

Sean P. McGrath, 35, 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. From 1998 to 2002, Mr. McGrath was Assistant Controller of Asplundh Tree Expert Co., a utility services and vegetation management company. Mr. McGrath is a Certified Public Accountant.

Lisa Washington, 39, 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.

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 2006.

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 $2.3 million for compensation and benefits related to our executive officers and $28.6 million for direct reimbursements, including certain costs that have been capitalized by us, during 2006.

Information Concerning the Audit Committee

Our managing board has a standing audit committee. All of the members of the audit committee are independent directors as defined by NYSE rules. The members of the audit committee are Mr. Rudolph, Mr. Clifford and 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.

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., 311 Rouser 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 on our website at www.atlaspipelinepartners.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The compensation committee of Atlas America, our general partner s indirect parent, is responsible for formulating and presenting recommendations to its Board of Directors and our managing board with respect to the compensation of our named executive officers. We do not directly compensate the named executive officers. Rather, Atlas America and its affiliates allocated the compensation of the executive officers between activities on behalf of our general partner and us and activities on behalf of itself and it 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 our general partner for the compensation allocated to us. The compensation allocation was $2.3 million for the year ended December 31, 2006. 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 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 named executive officers 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 named executive officers for fiscal 2006 specifically was intended:

- To encourage and reward strong performance; and

- To motivate our named executive officers by providing them with a meaningful equity stake in our company.

Accounting and cost implications of compensation programs are considered in program design; however, the main driver of design is alignment with our business needs.

Overview of Compensation Process

The compensation committee retained Mercer Human Resource Consulting in June 2006 to analyze and review the competitiveness and appropriateness of all elements of the total compensation (base salary and annual and long-term incentives) paid by Atlas America to its executive officers, including our named executive officers, individually and as a group. Mercer was asked to review compensation Atlas America awarded during 2005 and to assist the compensation committee in its analysis of 2006 awards. Mercer and the compensation committee looked not only to the oil and energy industry (adjusted for scope by position) in evaluating Atlas America s compensation levels but also, as appropriate, to the financial services industry.

The compensation committee focused on Atlas America s equity performance, market capitalization, corporate developments, business performance and financial position in determining the compensation for those named executive officers who provided services to both our parent and to us.

Our chief executive officer provided the compensation committee with statistical data and recommendations to assist it in determining compensation levels. While the compensation committee utilized this information and valued Mr. E. Cohen s observations with regard to Atlas America s performance, our performance and the performance of the named executive officers, the compensation committee also considered the analysis, recommendations, and review provided by Mercer. Ultimately the decisions regarding executive compensation were made by the compensation committee after extensive discussion regarding appropriate compensation and were approved by Atlas America s Board of Directors and the managing board of our general partner.

In addition to making decisions regarding compensation for the named executive officers, during 2006, the compensation committee also developed and articulated a compensation philosophy based on Atlas America s and our business strategy, significant growth, organizational structure, and future objectives. The compensation philosophy includes a frame of reference for compensation comparisons, target positioning, and objectives by pay element.

Additionally, the compensation committee established a formalized process for approving future compensation decisions, including base salary increases and annual and long-term incentive awards.

Elements of our Compensation Program

Base Salary

Base salary is intended to provide fixed compensation to the named executive officers 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. Mercer s analysis of compensation of executive officers within the energy industry (adjusted for scope by position) and confirmed that the base salaries paid to the named executive officers in fiscal 2006 fall between the median and the 75^{th} percentile of the energy industry. Mercer also referenced financial services data where appropriate.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the named executive officer s compensation to Atlas America s annual performance and our annual performance and/or to the performance of one of Atlas America s subsidiaries or divisions for which he or she is responsible. Additionally, the annual incentive allows Atlas America to recognize an individual s performance in relation to Atlas America s performance or that of one of its subsidiaries or divisions. 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 annual incentives paid in 2007 for 2006 performance were based upon the performance of Atlas America, our company and the individual, including initiatives undertaken by our named executive officers, during the year.

Long-Term Incentives

We believe that our long term success depends upon aligning executives and unitholders interests. To support this objective, we provide our executives with the opportunity to become significant shareholders, through our long-term incentive programs and the long-term incentive plan of Atlas Pipeline Holdings, which we refer to as the AHD Plan. 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 named executive officers who do not work full time for us also are eligible to receive awards under the Atlas America Stock Incentive Plan, which we refer to as the Atlas Plan. No awards were granted to our named executive officers under the Atlas Plan in 2006. Messrs. E. Cohen, J. Cohen, Jones and Firth were granted phantom units under our long-term incentive plan, which we refer to as our Plan and, based on their efforts in connection with the Atlas Pipeline Holdings initial public offering, received special recognition grants of phantom units and stock options under the AHD Plan.

Historically, the date upon which equity awards have been granted has not been fixed. If we do grant equity awards in the future, we shall do so in February of each year.

Supplemental Benefits, Deferred Compensation and Perquisites

We do not emphasize supplemental benefits for executives, and perquisites are discouraged. None of our named executive officers have deferred any portion of their compensation.

Compensation Determination

In determining compensation amounts awarded, the compensation committee focused on specific contributions by the named executive officers to the overall performance of Atlas America and its subsidiaries, including us and our general partner, during 2006.

The following table sets forth the compensation allocation for fiscal year 2006 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.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) [1]	Option Awards ($) [2]	All Other Compensation ($)	Total ($)
Edward E. Cohen, Chairman of the Board and Chief Executive Officer of Atlas Pipeline GP	2006	$ 180,000	$ 360,000	$ 674,625	$ 84,861	$ 32,300 (3)	$ 1,331,786
Matthew A. Jones, Chief Financial Officer of Atlas Pipeline GP	2006	$ 105,000	$ 210,000	$ 276,546	$ 16,972	$ 7,650(4)	$ 616,168
Jonathan Z. Cohen, Vice Chairman of Atlas Pipeline GP	2006	$ 190,000		$ 439,563	$ 48,527	$ 20,400 (5)	$ 698,490
Robert R. Firth, Chief Operating Officer & President of Atlas Pipeline Mid-Continent	2006	$ 250,000	$ 150,000	1,806,506	$ 61,100		$ 2,267,606

(1) Represents the dollar amount of (i) expense recognized by us for financial statement reporting purposes with respect to phantom units granted under our Plan and our incentive compensation arrangements (see Note 13 to our consolidated financial statements), and (ii) expense recognized by Atlas Pipeline Holdings for financial statement reporting purposes with respect to phantom units granted under the AHD Plan, all in accordance with FAS 123R.

(2) Represents the dollar amount of expense recognized for financial reporting purposes by Atlas Pipeline Holdings for options granted under the AHD Plan in accordance with FAS 123R.

(3) Represents payments on distribution equivalent rights (DERs) of $17,000 with respect to the phantom units awarded under our Plan and $15,300 with respect to phantom units awarded under the AHD Plan.

(4) Represents payments on DERs of $4,250 with respect to the phantom units awarded under our Plan and $3,400 with respect to phantom units awarded under the AHD Plan.

(5) Represents payments on DERs of $12,750 with respect to the phantom units awarded under our Plan and $7,650 with respect to phantom units awarded under the AHD Plan.

As required by SEC guidance, the table also discloses awards under the AHD Plan. No awards were granted to our named executive officers under the Atlas Plan in 2006.

2006 GRANTS OF PLAN-BASED AWARDS TABLE

Name	Grant Date	Approval Date	All Other Stock Awards: Number of Shares of Stock or Units (#) (1) (2)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / unit)	Grant Date Fair Value of Stock and Option Awards
Edward E. Cohen	11/1/06	10/31/06	20,000 (1)			$ 943,800 (1)
	11/10/06	10/31/06	90,000 (2)	500,000 (3)	$ 22.56	$ 2,030,400 (2)
						$ 1,880,000 (3)
Matthew A. Jones	11/1/06	10/31/06	5,000 (1)			$ 235,950 (1)
	11/10/06	10/31/06	20,000 (2)	100,000 (3)	$ 22.56	$ 451,200 (2)
						$ 376,000 (3)
Jonathan Z. Cohen	11/1/06	10/31/06	15,000 (1)			$ 707,850 (1)
	11/10/06	10/31/06	45,000 (2)	200,000 (3)	$ 22.56	$ 1,015,200 (2)
						$ 752,000 (3)
Robert R. Firth	11/10/06	10/31/06	45,000 (2)	360,000 (3)	$ 22.56	$ 1,015,200 (2)
						$ 1,353,600 (3)

(1) Represents grants of phantom units under our Plan, which vest 25% per year on the anniversary of the grant, valued in accordance with FAS 123R at the closing price of our common units on the grant date of $47.19.

(2) Represents grants of phantom units under the AHD Plan, which vest 25% on the third anniversary and 75% on the fourth anniversary of the grant, valued in accordance with FAS 123R at the closing price of Atlas Pipeline Holdings common units on the grant date of $22.56.

(3) Represents grants of stock options under the AHD Plan, which vest 25% on the third anniversary and 75% on the fourth anniversary of the grant, valued at $3.76 per option using the Black-Scholes option pricing model to estimate the weighted average fair value of each unit option granted with weighted average assumptions for (a) expected dividend yield of 4.0%, (b) risk-free interest rate of 4.5%, (c) expected volatility of 20.0%, and (d) an expected life of 6.9 years, as follows: Mr. E. Cohen 500,000; Mr. J. Cohen 200,000; Mr. Jones 100,000; and Mr. Firth 360,000.

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 expires on July 16, 2007, unless extended or earlier terminated. 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 provides the following regarding termination and termination benefits:

If Atlas America terminates Mr. Firth without cause before July 16, 2007, he is entitled to receive (a) his base salary and health insurance coverage otherwise payable through July 16, 2007, (b) an amount equal to 67% of the base incentive and additional incentive, described above, provided that the conditions for their award have otherwise been satisfied and (c) the acquisition look-back incentive.

If Mr. Firth terminates his employment for good reason upon 30 days notice, Mr. Firth is entitled to receive his base salary and health insurance coverage otherwise payable through July 16, 2007. Good reason is defined as a substantial change in Mr. Firth s function, duties and responsibilities resulting in a significant loss of authority or control; a significant reduction in benefits; relocation to a city other than Tulsa, Oklahoma or Atlas America s breach of any material provision of the agreement that is not cured within 30 days of notice.

Mr. Firth may terminate the agreement upon 90 days notice, in which event he will receive his base salary through the termination date stated in Mr. Firth s notice.

Atlas America may terminate Mr. Firth upon 5 days notice if Mr. Firth breaches any material obligation under the agreement; habitually neglects his duties; fails or refuses to perform, after 15 days prior notice, the reasonable and lawful directives of Atlas America s board; engages in conduct that is dishonest, damages our reputation or violates Atlas America s official policies; or is convicted of a felony or other crime involving moral turpitude.

The agreement restricts Mr. Firth, for 18 months following the termination of his employment, from engaging in any business in direct competition with Atlas America or us located in the counties in which we or Atlas America maintains operations or in which Mr. Firth worked; soliciting any of Atlas America s or our clients; and recruiting, soliciting or hiring any of Atlas America s employees or consultants. 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.

If a termination event had occurred as of December 31, 2006, we estimate that the value of the benefits to Mr. Firth would have been as follows:

Reason for termination	**Base salary**	**Incentive award**	**Benefits**	**Accelerated vesting of stock awards and option awards**
Termination by us without cause	$ 250,000	$ 2,893,563(1)	$ 10,029(2)	
Termination by Mr. Firth for good reason	$ 250,000		$ 10,029	
Termination by Mr. Firth without cause	$ 250,000			
Mr. Firth s death or disability				$ 1,690,000(3)

(1) In calculating the incentive award, we assumed that (a) the conditions to receipt of the base incentive and additional incentive awards, as described in Executive Group Incentive Program below, were fulfilled as of December 31, 2006, (b) in calculating the acquisition look-back incentive, that our distribution for the quarter ending December 31, 2008 would be the same as our distribution for the quarter ended December 31, 2006, and the distributable cash flow, as defined within the agreement, for the respective acquisitions for the year ending December 31, 2008 would be the same as that for the year ended December 31, 2006, and (c) based on these assumptions, Mr. Firth would be awarded 60,283 of our common units, whose value is based on their closing price on December 29, 2006.

(2) Represents rates currently in effect for COBRA insurance benefits for 6 months.

(3) Represents the value of unvested and accelerated options awards and unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 29, 2006. The payments relating to unit awards are calculated by multiplying the number of accelerated units by the closing price of the applicable units on December 29, 2006.

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.

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 29,053 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 29,053 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 Elk City 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.

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, 2006, phantom units granted under the AHD Plan generally vest 25% three years from the date of grant and 100% four years from 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, 2006, unit options granted generally will vest 25% three years from the date of grant and 100% four years from 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. This year, the compensation committee approved grants under the AHD Plan conditioned upon the filing of a Registration Statement on Form S-8.

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.

As required by SEC guidelines, the following table disclosed awards under our Plan as well as 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	450,000 (1)		$ 25.47	7/1/2015	47,500 (2)	$ 2,280,000 (3)
		500,000 (4)	$ 22.56	11/10/2016	90,000 (5)	$ 2,149,200 (6)
Matthew A. Jones	30,000 (7)	90,000 (8)	$ 25.47	7/1/2015	16,250(9)	$ 780,000 (3)
		100,000 (10)	$ 22.56	11/10/2016	20,000 (11)	$ 472,600 (6)
Jonathan Z. Cohen	300,000(12)		$ 25.47	7/1/2015	31,875 (13)	$ 1,530,000 (3)
		200,000 (14)	$ 22.56	11/10/2016	45,000 (15)	$ 1,074,600 (6)
Robert R. Firth	7,500(16)	22,500 (17)	$ 25.47	7/1/2015	2,250 (18)	$ 108,000 (3)
		360,000 (19)	$ 22.56	11/10/2016	45,000 (20)	$ 1,074,600 (6)

(1) Represents options to purchase Atlas America stock, granted on 7/1/05, which vested immediately.

(2) Represents our phantom units, which vest as follows: 3/16/07 5,000; 6/8/07 6,250; 11/1/07 5,000; 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; includes 20,000 units reported in 2006 Grants of Plan-Based Awards Table.

(3) Based on closing market price of our common units on December 29, 2006 of $48.00.

(4) Represents Atlas Pipeline Holdings options (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 125,000 and 11/10/10 375,000.

(5) Represents Atlas Pipeline Holdings phantom units (all of which are reported in 2006 Grants of Plan-Based Awards Table), 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 29, 2006 of $23.88.

(7) Represents options to purchase Atlas America stock.

(8) Represents options to purchase Atlas America stock, which vest as follows: 7/1/07 30,000; 7/1/08 30,000 and 7/1/09 30,000.

(9) Represents our phantom units, which vest as follows: 3/16/07 3,750; 11/1/07 1,250; 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; includes 5,000 units reported in 2006 Grants of Plan-Based Awards Table.

(10) Represents our options (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 25,000 and 11/10/10 75,000.

(11) Represents Atlas Pipeline Holdings phantom units (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 5,000 and 11/10/10 15,000.

(12) Represents options to purchase Atlas America stock, granted on 7/1/05, which vested immediately.

(13) Represents our phantom units, which vest as follows: 3/16/07 3,125; 6/8/07 3,750; 11/1/07 3,750; 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; includes 15,000 units reported in 2006 Grants of Plan-Based Awards Table.

(14) Represents Atlas Pipeline Holdings options (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 50,000 and 11/10/10 150,000.

(15) Represents Atlas Pipeline Holdings phantom units (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 11,250 and 11/10/10 33,750.

(16) Represents options to purchase Atlas America stock.
(17) Represents options to purchase Atlas America stock, which vest as follows: 7/1/07 7,500; 7/1/08 7,500 and 7/1/09 7,500.
(18) Represents our phantom units, which vest as follows: 3/16/07 750; 3/16/08 750; 3/16/09 750.
(19) Represents Atlas Pipeline Holdings options (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 90,000 and 11/10/10 270,000.
(20) Represents Atlas Pipeline Holdings options (all of which are reported in 2006 Grants of Plan-Based Awards Table), which vest as follows: 11/10/09 90,000 and 11/10/10 270,000.

2006 OPTION EXERCISES AND STOCK VESTED TABLE

	Stock Awards	
	Number of Shares Acquired on Vesting	Value Realized on Vesting
Name	(#)	($)
Edward E. Cohen	11,250	$ 454,612
Matthew A. Jones	3,750	$ 151,537
Jonathan Z. Cohen	6,875	$ 277,819
Robert R. Firth	750	$ 30,307

DIRECTOR COMPENSATION TABLE

	Fees Earned or Paid in Cash	Stock Awards	All Other Compensation	Total
Name	($)	($)	($)	($)
Tony C. Banks	$ 35,000	$ 14,992 (1)	$ 2,735	$ 52,727
Curtis D. Clifford	$ 35,000	$ 14,988 (2)	$ 2,814	$ 52,802
Gayle P.W. Jackson	$ 35,000	$ 14,964(3)	$ 1,832	$ 51,796
Martin Rudolph	$ 35,000	$ 14,964(3)	$ 1,832	$ 51,796

(1) Represents 371 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: 2/13/07 92; 2/13/08 92; 2/13/09 92; 2/13/10 95.

(2) Represents 363 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: 5/10/07 90; 5/10/08 90; 5/10/09 90; 5/10/10 93.

(3) Represents 364 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: 3/17/07 91; 3/17/08 91; 3/17/09 91; 3/17/10 91.

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 2006, 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

The following table sets forth the number and percentage of shares of common stock owned, as of March 7, 2007, 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 311 Rouser Road, Moon Township, Pennsylvania 15108.

Name of Beneficial Owner	Common Units	Percent of Class
Members of the Managing Board		
Edward E. Cohen	26,600 (1)	*
Jonathan Z. Cohen	17,727 (2)	*
Michael L. Staines	6,000 (3)	*
Matthew A. Jones	7,500 (4)	*
Tony C. Banks	287	*
Curtis D. Clifford	331	*
Gayle P.W. Jackson	245 (5)	*
Martin Rudolph	745 (6)	*
Executive Officers		
Robert R. Firth	1,500 (7)	*
Executive officers and managing board members as a group (9 persons)	60,935	*
Other Owners of More than 5% of Outstanding Units		
Atlas Pipeline Partners GP, LLC	1,641,026	12.55%
Kayne Anderson Capital Advisors/Richard A. Kayne	933,100(8)	7.13%
Elliott Associates, L.P.	975,610(9)	7.46%

* 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 168 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 168 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 which was filed with the SEC on January 12, 2007. The address for Kayne Anderson Capital Advisors and Richard A. Kayne is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, CA 90067.

(9) This information is based upon a Schedule 13G which was filed with the SEC on January 12, 2007. The address for Elliott Associates, L.P. is 712 Fifth Avenue, 36th Floor, New York, NY 10019.

Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2006:

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	159,067	$ 0.00	275,933

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

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	220,492	$ 0.00	
Equity compensation plans approved by security holders unit options	1,215,000	$22.56	
Equity compensation plans approved by security holders Total	1,435,492		664,508

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

Plan category	(a) Number of securities to be issued upon	(b) Weighted-average exercise price of	(c) Number of securities remaining available for future issuance under

	exercise of outstanding equity instruments	outstanding equity instruments	equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	1,241,511	$26.59	754,348

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

We do not directly employ any persons to manage or operate our business. These functions are provided by our general partner and employees of 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 $2.3 million for the year ended December 31, 2006 for compensation and benefits related to their employees, and reimbursed $28.6 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, 2006 and 2005 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2006	2005
Audit fees (1)	$ 1,274,304	$ 1,068,515
Audit related fees (2)	44,534	482,447
Tax fees (3)	94,973	291,007
Total aggregate fees billed	$ 1,413,811	$ 1,841,969

(1) Includes 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) Includes the aggregate fees recognized in each of the last two years for products and services provided by Grant Thornton LLP, other than those services described above. Services in this category relate principally to acquisitions, filings on Form S-3, and private placement offerings.

(3) Includes 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 2006.

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
3.1	Certificate of Limited Partnership[1]
3.2	Second Amended and Restated Agreement of Limited Partnership[2]
3.3	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units [3]
4.1	Common unit certificate[1]
10.1	Revolving Credit and Term Loan Agreement dated as of April 14, 2005 among Registrant, Wachovia Bank, National Association, and the other parties named therein[4]
10.1(a)	First Amendment to Revolving Credit and Term Loan Agreement dated as of October 31, 2005[5]
10.1(b)	Second Amendment to Revolving Credit and Term Loan Agreement dated as of May 1, 2006[6]
10.1(c)	Third Amendment to Revolving Credit and Term Loan Agreement dated as of June 29, 2006[6]
10.2	Amendment and Joinder to Gas Gathering Agreements dated as of December 18, 2006 among Atlas Pipeline Partners, L.P., Atlas Pipeline Operating Partnership, L.P., Atlas America, Inc., Resource Energy, LLC, Viking Resources, LLC, Atlas Noble, LLC, Atlas Resources, LLC, Atlas America, LLC, Atlas Energy Resources, LLC and Atlas Energy Operating Company, LLC
10.3	Amendment and Joinder to Omnibus Agreement dated as of December 18, 2006 among Atlas Pipeline Partners, L.P., Atlas Pipeline Operating Partnership, L.P., Atlas America, Inc., Resource Energy, LLC, Viking Resources, LLC, Atlas Energy Resources, LLC and Atlas Energy Operating Company, LLC
10.4	Amended and Restated Agreement of Limited Partnership of NOARK Pipeline System, Limited Partnership dated January 12, 1998[5]
10.4(a)	First Amendment to Amended and Restated Agreement of Limited Partnership of NOARK Pipeline System, Limited Partnership dated June 18, 1998[5]
10.5	Employment Agreement dated as of July 16, 2004 between Atlas America, Inc. and Robert R. Firth
10.5(a)	Letter Agreement re: Incentive Compensation for Executive Group among Robert R. Firth, David D. Hall and Atlas Pipeline Partners, L.P.
10.5(b)	Amendment to Letter Agreement dated as of July 14, 2006
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges

21.1	Subsidiaries of Registrant
23.1	Consent of Grant Thornton LLP
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to current report on Form 8-K on March 14, 2006.
(4) Previously filed as an exhibit to current report on Form 8-K on April 18, 2005.
(5) Previously filed as an exhibit to current report on Form 8-K on November 4, 2005.
(6) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2006.

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

March 14, 2007

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 March 9, 2007.

/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