Atlas America, Inc.

Atlas America, Inc. | 2006 Annual Report

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **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: **001-32169**

ATLAS AMERICA, INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0404430**
(State or other jurisdiction or incorporation or organization)	**(I.R.S. Employer Identification No.)**
311 Rouser Road Moon Township, PA	**15108**
(Address of principal executive offices)	**Zip Code**

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

Securities registered pursuant to Section 12(b) of the Act: None

Title of each class	Name of each exchange on which registered
None	**None**

Securities registered pursuant to Section 12(g) of the Act:

Common stock, par value $.01 per share
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 ☐

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 ☒

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 ☒ 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 a 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 ☐ 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 ☒

The aggregate market value of the voting common stock held by non-affiliates of the registrant, based on the closing price of such stock on the last business day of the registrant's most recently completed second quarter, June 30, 2006, was $757.6 million.

The number of outstanding shares of the registrant's common stock on February 25, 2007 was 19.4 million shares.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS AMERICA, INC. AND SUBSIDIARIES
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PART I

ITEM 1: BUSINESS

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.

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.

General

We are an energy company engaged, through subsidiaries, in the development, production and transportation of natural gas and, to a lesser extent, oil. We have been involved in the energy industry since 1968. We began to expand operations at the end of 1998 when we acquired The Atlas Group, Inc. and a year later when we acquired Viking Resources Corporation, both energy finance and production companies.

We conduct our development and production operations through Atlas Energy Resources, LLC (NYSE: ATN), which we refer to as Atlas Energy or ATN, in which we own approximately 80% of the common units. Atlas Energy focuses its operations in the Appalachian Basin.

We conduct our natural gas transportation and processing operations through Atlas Pipeline Partners, L.P. (NYSE: APL), which we refer to as Atlas Pipeline or APL. The general partner of Atlas Pipeline is Atlas Pipeline Partners GP, LLC, which we refer to and Atlas Pipeline GP, a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (NYSE: AHD), which we refer to as Atlas Pipeline Holdings or AHD, in which we own an 82.9% interest. Atlas Pipeline GP has a 2% general partner interest, a 12.5% limited partner interest and all incentive distribution rights in Atlas Pipeline.

Before 2004, we were a wholly-owned subsidiary of Resource America, Inc. (NASDAQ: REXI). In May 2004, we completed our initial public offering of 2,645,000 shares of our common stock at a price of $15.50 per common share. The net proceeds of the offering of $37.0 million, after deducting underwriting discounts and costs, were distributed to our then parent, Resource America, in the form of a non-taxable dividend. In June 2005, Resource America spun us off by distributing its remaining 10.7 million shares of our common stock to its stockholders in the form of a tax-free dividend.

In June 2006, we changed our year end to December 31 from September 30 and therefore information is included in this report for the three months ended December 31, 2005, which we refer to as our transition period, and the year ended December 31, 2006.

Atlas Energy

In December 2006, we contributed substantially all of our natural gas and oil assets and our investment partnership management business to Atlas Energy, a then wholly-owned subsidiary. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a 19.5% ownership interest, in an initial public offering at a price of $21.00 per unit. The net proceeds of approximately $139.9 million, after underwriting discounts and commissions, were distributed to us.

Atlas Energy is a limited liability company focused on the development and production of natural gas and, to a lesser extent, oil in the Appalachian Basin region of the United States, principally in western New York, eastern Ohio, Western Pennsylvania and Tennessee. Atlas Energy funds the drilling of natural gas and oil wells on its acreage by sponsoring and managing tax-advantaged investment partnerships. It generally structures its investment partnerships so that, upon formation of a partnership, Atlas Energy co-invests in and contributes leasehold acreage to it, enters into drilling and well operating agreements with it and becomes its managing general partner. Atlas Energy is managed by Atlas Energy Management, Inc., through which we provide Atlas Energy with the personnel necessary to manage its assets and raise capital.

We derive revenues from Atlas Energy from:

- our ownership of common units representing an 80% interest and Atlas Energy Management's ownership of Class A units representing a 2% interest in Atlas Energy; and
- Atlas Energy Management's incentive distribution rights, which entitle it to receive increasing percentages, up to a maximum of 25%, of cash distributed by Atlas Energy as it reaches targeted distribution levels in excess of $0.42 per common unit.

As of December 31, 2006, Atlas Energy had the following principal assets:

- an investment partnership business, which includes equity interests in 92 investment partnerships and a registered broker-dealer which acts as the dealer manager for Atlas Energy's investment partnership offerings;
- either directly or through the investment partnerships, working interests in 7,252 gross producing gas and oil wells including overriding royalty interests in 634 gross producing gas and oil wells;
- approximately 601,400 gross (547,700 net) acres of which 336,700 gross (323,300 net) acres, are undeveloped; and
- an interest in a joint venture that gives Atlas Energy the right to drill up to 500 net wells before December 31, 2007 (of which 141 wells had been drilled as of December 31, 2006) on approximately 212,000 acres in Tennessee.

In addition, at December 31, 2006, the date of Atlas Energy's most recent reserve report, it had proved reserves of 180.9 Bcfe, including the reserves net to its equity interest in the investment partnerships and its direct interests in producing wells.

For the year ended December 31, 2006, Atlas Energy produced 24.5 million cubic feet of natural gas, or mmcf of natural gas per day, which includes the proportionate share of production from its investment partnerships as well as its direct interests in producing wells.

Atlas Energy derives substantially all of its revenues from its equity interest in the oil and gas produced by the investment partnerships as well as the fees paid by the partnerships to it for acting as the managing general partner as follows:

- *Gas and oil production.* Atlas Energy receives an interest in each investment partnership proportionate to the value of its coinvestment in it and the value of the acreage it contributes to it, typically 27% to 30% of the overall capitalization of a particular partnership. Atlas Energy also receives an incremental interest in each partnership, typically 7%, for which it does not make any additional capital contribution. Consequently, its equity interest in the reserves and production of each partnership is typically between 34% and 37%.
- *Partnership management*. As managing general partner of its investment partnerships, Atlas Energy receives, for each well drilled by it for an investment partnership, a fixed fee of approximately $15,000 per well and a 15% mark-up on costs incurred to drill and complete the well. In addition, Atlas Energy receives per well monthly administrative and operating fees.

Gas and Oil Production

As of December 31, 2006, Atlas Energy owned interests in 7,252 gross wells, principally in the Appalachian Basin, of which it operated 6,155. In the two years ended September 30, 2005, transition period ended December 31, 2005 and year ended December 31, 2006, we and Atlas Energy have drilled 2,074 gross (682 net) wells, 98% of which were successful in producing natural gas in commercial quantities, including 715 gross wells in the year ended December 31, 2006, 99% of which were successful.

In September 2004, we expanded operations into Tennessee through a joint venture with Knox Energy, LLC that gave Atlas Energy an exclusive right to drill up to 300 net wells through June 30, 2007 on approximately 212,000 acres owned by Knox Energy. This agreement was amended and extended, giving Atlas the right to drill an additional 200 net wells from January 1, 2007 to December 31, 2007, provided that Atlas Energy commences the drilling of a minimum of 75 wells before September 30, 2007. As of December 31, 2006, Atlas Energy had drilled 141 net wells under this agreement. In addition, Atlas Energy has identified over 500 proved undeveloped drilling locations and approximately 2,600 additional potential drilling locations on its acreage and the Tennessee joint venture acreage at December 31, 2006.

Because the Appalachian Basin is located near the energy-consuming regions of the mid-Atlantic and northeastern United States, Appalachian producers have historically sold their natural gas at a premium to the benchmark price for natural gas on the NYMEX. For the year ended December 31, 2006, the average premium over NYMEX for natural gas delivered to our primary delivery points in the Appalachian Basin was $0.36 per mmbtu. In addition, most of our natural gas production has a high Btu content, resulting in an additional premium to NYMEX natural gas prices.

For more detailed information concerning Atlas Energy's natural gas and oil properties and production quantities, including the number of wells in which it has a working interest, reserve and acreage information, average sales price and average production costs, see Item 2, "Properties" in this report.

Partnership Management

Because Atlas Energy generally funds its drilling activities through sponsorship of tax-advantaged investment partnerships, the amount of development activities it will undertake depends in part upon its ability to obtain investor subscriptions to the partnerships. Atlas Energy raised $218.5 million in the year ended December 31, 2006, $52.2 in the three months ended December 31, 2005 and $148.7 million in 2005. During the year ended December 31, 2006, its investment partnerships invested $283.7 million in drilling and completing wells, of which Atlas Energy contributed $65.2 million. During the three months ended December 31, 2005, its investment partnerships invested $68.3 million in drilling and completing wells, of which Atlas Energy contributed $16.1 million. During 2005, its investment partnerships invested $206.0 million in drilling and completing wells, of which Atlas Energy contributed $57.3 million.

Atlas Energy's investment partnerships provide tax advantages to their investors because an investor's share of the partnership's intangible drilling cost deduction may be used to offset ordinary income. Intangible drilling costs include items that do not have salvage value, such as labor, fuel, repairs, supplies and hauling. Historically, approximately 90% of the subscription proceeds received by each partnership have been used to pay 100% of the partnership's intangible drilling costs. For example, an investment of $10,000 has generally permitted the investor to deduct approximately $9,000 in the year in which the investor invests.

Management Agreement between Atlas Energy Management and Atlas Energy

Upon completion of the Atlas Energy initial public offering, our subsidiary, Atlas Energy Management, entered into a management agreement with Atlas Energy pursuant to which Atlas Energy Management will manage Atlas Energy's business affairs under the supervision of its board of directors. Atlas Energy Management will provide Atlas Energy with all services necessary or appropriate for the conduct of its business. In exercising its powers and discharging its duties under the management agreement, Atlas Energy Management must act in good faith.

Before making any distribution on its common units, Atlas Energy will reimburse Atlas Energy Management for all expenses that it incurs on Atlas Energy's behalf pursuant to the management agreement. These expenses will include costs for providing corporate staff and support services to Atlas Energy. Atlas Energy Management will charge on a fully-allocated cost basis for services provided to Atlas Energy. This fully-allocated cost basis is based on the percentage of time spent by personnel of Atlas Energy Management and its affiliates on Atlas Energy's matters and includes the compensation paid by Atlas Energy Management and its affiliates to such persons and their allocated overhead. The allocation of compensation expense for such persons will be determined based on a good faith estimate of the value of each such person's services performed on Atlas Energy's business and affairs, subject to the periodic review and approval of the Atlas Energy's audit or conflicts committee.

Atlas Energy Management, its stockholders, directors, officers, employees and affiliates will not be liable to Atlas Energy, any subsidiary of Atlas Energy, Atlas Energy's directors or Atlas Energy's unitholders for acts or omissions performed in good faith and in accordance with and pursuant to the management agreement, except by reason of acts constituting gross negligence, bad faith, willful misconduct, fraud or a knowing violation of criminal law. Atlas Energy will indemnify Atlas Energy Management, its stockholders, directors, officers, employees and affiliates with respect to all expenses, losses, damages, liabilities, demands, charges and claims arising from acts of Atlas Energy Management, its stockholders, directors, officers, employees and affiliates not constituting gross negligence, bad faith, willful misconduct, fraud or a knowing violation of criminal law performed in good faith in accordance with and pursuant to the management agreement. Atlas Energy Management and its affiliates will indemnify Atlas Energy and Atlas Energy's directors and officers with respect to all expenses, losses, damages, liabilities, demands, charges and claims arising from acts of Atlas Energy Management or its affiliates constituting gross negligence, bad faith, willful misconduct, fraud or a knowing violation of criminal law or any claims by employees of Atlas Energy Management or its affiliates relating to the terms and conditions of their employment. Atlas Energy Management and/or Atlas America will carry errors and omissions and other customary insurance.

The management agreement may not be amended without the prior approval of Atlas Energy's conflicts committee if the proposed amendment will, in the reasonable discretion of Atlas Energy's board, adversely affect common unitholders.

The management agreement does not have a specific term; however, Atlas Energy Management may not terminate the agreement before December 18, 2016. Atlas Energy may terminate the management agreement only upon the affirmative vote of holders of at least two-thirds of its outstanding common units, including units held by us. In the event Atlas Energy terminates the management agreement, Atlas Energy Management will have the option to require the successor manager, if any, to purchase the membership interests and management incentive interests for their fair market value as determined by agreement between the departing manager and the successor manager.

Sales

Natural Gas. Atlas Energy has a natural gas supply agreement with Hess Corporation which is valid through March 31, 2009. Subject to certain exceptions, Hess Corporation has a last right of refusal to buy all of the natural gas produced and delivered by Atlas Energy and its affiliates, including its investment partnerships, at certain delivery points with the facilities of:

- East Ohio Gas Company, National Fuel Gas Distribution, Columbia Gas of Ohio, and Peoples Natural Gas Company, which are local distribution companies; and
- National Fuel Gas Supply, Columbia Gas Transmission Corporation, Tennessee Gas Pipeline Company, and Texas Eastern Transmission Company, which are interstate pipelines.

A portion of Atlas Energy's and its investment partnerships' natural gas is subject to the agreement with Hess Corporation, with the following exceptions:

- natural gas it sells to Warren Consolidated, an industrial end-user and direct delivery customer;
- natural gas that at the time of the agreement was already dedicated for the life of the well to another buyer;
- natural gas that is produced by a company which was not an affiliate of Atlas Energy at the time of the agreement;
- natural gas sold through interconnects established subsequent to the agreement;
- natural gas that is delivered to interstate pipelines or local distribution companies other than those described above; and
- natural gas that is produced from wells operated by a third-party or subject to an agreement under which a third-party was to arrange for the gathering and sale of the natural gas.

Based on the most recent monthly production data available to us as of December 31, 2006, we anticipate that Atlas Energy and its affiliates, including its investment partnerships, will sell approximately 30% of its natural gas production during the twelve months ending December 31, 2007 under the Hess Corporation agreement. The agreement requires the parties to negotiate a new pricing arrangement at each annual delivery point. If, at the end of any applicable period, the parties cannot agree to a new price for any delivery point, then Atlas Energy may solicit offers from third parties to buy the natural gas for that delivery point. If Hess Corporation does not match this price, then Atlas Energy may sell the natural gas to the third party. Atlas Energy markets the remainder of its natural gas, which is principally located in the Fayette County, PA area, primarily to Colonial Energy, Inc., UGI Energy Services, and others. During the twelve months ended December 31, 2006, Atlas Energy received an average of $8.83 per mcf of natural gas, compared to $11.06 in the three months ended December 31, 2005, $7.26 per mcf in fiscal 2005 and $5.84 per mcf in fiscal 2004.

We expect that natural gas produced from Atlas Energy's wells drilled in areas of the Appalachian Basin other than those described above will be primarily tied to the spot market price and supplied to:

- gas marketers;
- local distribution companies;
- industrial or other end-users; and/or
- companies generating electricity.

Crude Oil. Crude oil produced from Atlas Energy's wells flows directly into storage tanks where it is picked up by the oil company, a common carrier, or pipeline companies acting for the oil company which is purchasing the crude oil. Unlike natural gas, crude oil does not present any transportation problem. Atlas Energy anticipates selling any oil produced by its wells to regional oil refining companies at the prevailing spot market price for Appalachian crude oil in spot sales.

Availability of Oil Field Services

Atlas Energy contracts for drilling rigs and purchases goods and services necessary for the drilling and completion of wells from a number of drillers and suppliers, none of which supplies a significant portion of its annual needs. During 2006, it faced no shortage of these goods and services. We cannot predict the duration of the current supply and demand situation for drilling rigs and other goods and services with any certainty due to numerous factors affecting the energy industry and the demand for natural gas and oil.

Atlas Pipeline Holdings and Atlas Pipeline

In July 2006, we contributed our ownership interests in Atlas Pipeline GP to Atlas Pipeline Holdings. Concurrent with this transaction, AHD issued 3,600,000 common units, representing a 17.1% ownership interest in it, in an initial public offering at a price of $23.00 per unit. The net proceeds of approximately $74.3 million, after underwriting discounts and commissions, were distributed to us. AHD, through its ownership of Atlas Pipeline GP, owns a 2% general partner interest and 1,641,026 common units constituting 12.5% of the outstanding common units of APL, or an 11.4% limited partner interest in APL.

AHD derives revenues from Atlas Pipeline Partners through its ownership of Atlas Pipeline GP, which in turn derives its revenues from:

- its 2% general partner interest in Atlas Pipeline Partners;
- its incentive distribution rights in Atlas Pipeline Partners which entitle it to receive increasing percentages, up to a maximum of 50%, of cash distributed by Atlas Pipeline Partners as it reaches targeted distribution levels in excess of $0.42 per common unit; and
- its 11.5% limited partner interest in Atlas Pipeline Partners.

APL is a publicly-traded midstream energy services provider engaged in the transmission, gathering and processing of natural gas. APL is 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, APL is a leading provider of natural gas processing services in Oklahoma. APL also provides interstate gas transmission services in southeastern Oklahoma, Arkansas and southeastern Missouri. APL conducts its business through two operating segments: its Mid-Continent operations and its Appalachian operations.

APL owns and operates through its Mid-Continent operations:

- a Federal Energy Regulatory Commission, or FERC, regulated, 565-mile interstate pipeline system, which we refer to as Ozark Gas Transmission, that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and has throughput capacity of approximately 322 mmcf/d;
- three natural gas processing plants with aggregate capacity of approximately 350 mmcf/d and one treating facility with a capacity of approximately 200 mmcf/d, 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 APL's natural gas processing plants or Ozark Gas Transmission.

APL owns and operates through its 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 APL and us and our affiliates, including Atlas Energy, APL gathers substantially all of the natural gas for its Appalachian Basin operations from wells operated by Atlas Energy. We describe these agreements under "—Our and Atlas Energy's Relationship with APL."

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

Both APL's 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 and APL's gathering systems are connected to approximately 7,200 central delivery points or wells, giving APL significant scale in its service areas. APL provides gathering and processing services to the wells connected to its systems, primarily under long-term contracts. APL provides fee-based, FERC-regulated transmission services through Ozark Gas Transmission under both long-term and short-term contractual arrangements. APL intends 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 its gathering and processing assets, APL management believes that it is strategically positioned to capitalize on the significant increase in drilling activity in its service areas and the positive price differential across Ozark Gas Transmission, also known as basis spread. APL intends to continue to expand its business through strategic acquisitions and internal growth projects, such as the construction of the Sweetwater gas processing plant and gathering system, that increase distributable cash flow. The Sweetwater plant, which began operations in September 2006, is located west of APL's Elk City gas plant in Beckham County, Oklahoma and has an operating capacity of 120 mmcf/d. The Sweetwater plant was built to further access natural gas production actively being developed in western Oklahoma and the Texas panhandle.

Our and Atlas Energy's Relationship with APL

In connection with Atlas Pipeline Partners' initial public offering in February 2000, we entered into an omnibus agreement and master natural gas gathering agreement with Atlas Pipeline Partners.

Omnibus Agreement

Under the omnibus agreement, we and our affiliates, including Atlas Energy, have agreed to add wells to APL's gathering systems and provide consulting services when APL constructs new gathering systems or extend existing systems. In December 2006, in connection with the completion of the initial public offering of Atlas Energy, and our contribution and sale of our natural gas and oil development and production assets to, it, Atlas Energy joined the omnibus agreement as an obligor (except for the provisions of the omnibus agreement imposing conditions upon the disposition of Atlas Pipeline GP's general partner interest in APL), and we 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 Atlas Pipeline GP is removed as general partner of APL without cause. The omnibus agreement may not be amended without the approval of the conflicts committee of the board of directors of Atlas Pipeline Holding's general partner if, in its reasonable discretion, such amendment will adversely affect APL's common unitholders. APL's common unitholders do not have explicit rights to approve any termination or material modification of the omnibus agreement.

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 APL's 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 APL's 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 APL, at its cost and expense, to extend its gathering system to connect to that well. With respect to other Atlas Energy wells that are more than 2,500 feet from APL's gathering systems, APL has the right, at its cost and expense, to extend its 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 APL elects not to exercise its right to extend its gathering systems, Atlas Energy may connect an Atlas Energy well to a natural gas gathering system owned by someone other than APL or one of APL's subsidiaries or to any other delivery point; however, APL will have the right to assume the cost of construction of the necessary flow lines, which will then become APL's property and part of its gathering systems.

Consulting Services. The omnibus agreement requires Atlas Energy to assist APL in identifying existing gathering systems for possible acquisition and to provide consulting services to APL in evaluating and making a bid for these systems. Atlas Energy must give APL notice of identification by it or any of its affiliates of any gathering system as a potential acquisition candidate, and must provide APL 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. APL must determine, within a time period specified by Atlas Energy's notice to AHD, which must be a reasonable time under the circumstances, whether it wants to acquire the identified system and advises Atlas Energy of its intent. If APL advises Atlas Energy that it does not intend to make the acquisition, does not complete the acquisition within a reasonable time period, or advises Atlas Energy that it does not intend to acquire the system, then Atlas Energy may do so.

Gathering System Construction. The omnibus agreement requires Atlas Energy to provide APL with construction management services if APL determines to expand one or more of its gathering systems. APL 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 APL's General Partner. Before the completion of the AHD and the Atlas Energy initial public offerings, we owned both Atlas Pipeline GP and the entities which act as the general partners, operators or managers of the drilling investment partnerships sponsored by us. The omnibus agreement prohibited us from transferring our interest in Atlas Pipeline GP, as general partner of APL, unless we also transferred to the same person our interests in those subsidiaries. We were permitted, however, to transfer our interest in Atlas Pipeline GP to a wholly- or majority-owned direct or indirect subsidiary as long as we continued to control the new entity. In connection with AHD initial public offering, we transferred our interest in APL's general partner to AHD, then our wholly-owned subsidiary. We currently own an 82.9% interest in AHD.

Natural Gas Gathering Agreements

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

- for natural gas from well interests allocable to Atlas Energy or its affiliates (excluding general or limited partnerships sponsored by them) that were connected to APL's 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 APL's 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 APL's gathering systems after February 2, 2000, and (iii) well interests allocable to third parties in wells connected to APL's 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 APL and for which APL assumes 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 APL's gathering systems. Pursuant to the contribution agreement between us and Atlas Energy, entered into at the completion of Atlas Energy's initial public offering, we agreed to assume Atlas Energy's obligation to pay gathering fees to APL. Atlas Energy, in turn, assigned to us the gathering fees it receives from the investment partnerships and gathering fees attributable to its production interest. Thus, we are responsible for the difference between the gathering fees payable to APL under the gathering agreement and the fees we receive from Atlas Energy.

The master natural gas gathering agreement is a continuing obligation and, accordingly, has no specified term or provisions regarding termination. However, if Atlas Pipeline GP is removed as general partner of APL 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 board of directors of Atlas Pipeline GP if, in the reasonable discretion of Atlas Pipeline GP , such amendment will adversely affect APL's common unitholders. APL's common unitholders do not have explicit rights to approve any termination or material modification of the master natural gas gathering agreement.

In addition to the master natural gas gathering agreement, APL has 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, APL receives a fee of $0.80 per Mcf. Under the third agreement, which covers wells owned by third parties unrelated to Atlas Energy, APL receives fees that range from $0.20 to $0.29 per Mcf, or from 10% to 16% of the weighted average sales price for the natural gas APL transports.

Natural Gas Supply

Substantially all of the natural gas APL transports in the Appalachian Basin is derived from wells operated by Atlas Energy pursuant to the agreements described under "–Our and Atlas Energy's Relationship with APL–Natural Gas Gathering Agreements."

In the Mid-Continent, APL has 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 APL's 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.

APL has enjoyed long-term relationships with the majority of its Mid-Continent producers. For instance, on the Velma system, where APL has producer relationships going back over 20 years, its top four producers, which accounted for a significant portion of Velma's 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 APL's gathering systems have evergreen term extensions.

Natural Gas and NGL Marketing

APL does not buy or sell gas in connection with its Appalachian operations. In Mid-Continent, APL typically sells natural gas to purchasers at the tailgate of its processing plants and at various delivery points on 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 APL currently sells the majority of its natural gas at the average of ONEOK Gas Transportation, LLC 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 APL's Elk City and Sweetwater plants, it sells substantially all of its 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 Energy Pipeline Company.

APL sells its NGL production to ONEOK Hydrocarbons Company under two separate agreements: the Velma agreement which expires February 1, 2011, and the Elk City and Sweetwater agreement which expires October 1, 2008. NGLs are priced under both agreements 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 APL's account to SemGroup, L.P. and EnerWest Trading while condensate collected at Elk City and Sweetwater is sold to TEPPCO Crude Oil, L.P.

Operating Segment Information

For financial information concerning our operating segments, including revenues from external customers, profit (loss) and total assets, see Note 13 to our Notes to Consolidated Financial Statements.

Hedging

Atlas Energy

Pricing for natural gas and oil production has been volatile and unpredictable for many years. To limit its exposure to changing natural gas prices, Atlas Energy uses financial and physical hedges for a portion of its natural gas production. Through its hedges, it seeks to provide a measure of stability in the volatile environment of natural gas prices. The financial hedges may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. The futures contracts are commitments to purchase or sell natural gas at future dates and generally cover one-month periods for up to 36 months in the future. To assure that the financial instruments will be used solely for hedging price risks and not for speculative purposes, Atlas Energy has a management committee to assure that all financial trading is done in compliance with its hedging policies and procedures. Atlas Energy does not intend to contract for positions that it cannot offset with actual production. As of December 31, 2006, Atlas Energy had financial hedges and physical hedges in place for approximately 79% of its expected production for the twelve months ending December 31, 2007.

Hess Corporation and other third-party marketers to which Atlas Energy sells gas, such as Colonial Energy, Inc. and UGI Energy Services, also use NYMEX-based financial instruments to hedge their pricing exposure and make price hedging opportunities available to Atlas Energy. Atlas Energy enters into physical hedge transactions which are not deemed hedges for accounting purposes because they require firm delivery of natural gas and are considered normal sales of natural gas. Atlas Energy generally limits these arrangements to much smaller quantities than those projected to be available at any delivery point. The price paid by Hess Corporation, Colonial Energy, Inc., UGI Energy Services, and any other third-party marketers for certain volumes of natural gas sold under these sales agreements may be significantly different from the underlying monthly spot market value. Fixed prices are defined as the price Atlas Energy established with the related purchaser and are not subject to change in the future.

Atlas Pipeline

APL's 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. APL mitigates 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.

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

APL is exposed to commodity price risks when natural gas is purchased for processing. The amount and character of this price risk is a function of APL's contractual relationships with natural gas producers, or, alternatively, a function of cost of sales. APL is 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: requires APL to pay a percentage of revenue to the producer. This results in APL being net long physical natural gas and NGLs.
- Keep-whole: requires APL to deliver the same quantity of natural gas at the delivery point as it received at the receipt point; any resulting NGLs produced belong to APL. This results in APL being long physical NGLs and short physical natural gas.

APL hedges 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.

APL recognizes gains and losses from the settlement of its hedges in revenue when it sells 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 APL sells the physical residue natural gas or NGLs. The majority of APL's hedges are characterized as cash flow hedges as defined in Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." APL determines 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, APL has established a hedging committee to review its hedges for compliance with its hedging policies and procedures. APL's revolving credit facility prohibits speculative hedging and limits its overall hedge position to 80% of its equity volumes.

For additional information on hedging activities and a summary of outstanding hedging instruments as of December 31, 2006, please see Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

Major Customers

Atlas Pipeline's NGLs and natural gas are sold under contract to various purchasers. For the year ended December 31, 2006, sales to two customers accounted for approximately 22% and 12% of our total consolidated revenues. Atlas Energy did not have any customers that exceeded 10% of our total consolidated revenues for the year ended December 31, 2006. During the year ended September 30, 2005, Atlas Pipeline had one customer that accounted for 20% of our total revenues. During the year ended September 30, 2004, gas sales to Amerada Hess (formerly FirstEnergy Solutions) accounted for 11% of our total consolidated revenues.

Competition

Atlas Energy

The energy industry is intensely competitive in all of its aspects. Atlas Energy operates in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through its investment partnerships, contracting for drilling equipment and securing trained personnel. Atlas Energy also competes with the exploration and production divisions of public utility companies for natural gas and oil property acquisitions. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Atlas Energy's competitors may be able to pay more for natural gas and oil properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Furthermore, competition arises not only from numerous domestic and foreign sources of natural gas and oil but also from other industries that supply alternative sources of energy. Product availability and price are the principal means of competition in selling oil and natural gas.

Many of Atlas Energy's competitors possess greater financial and other resources than ours which may enable them to identify and acquire desirable properties and market their natural gas and oil production more effectively than we do.

Moreover, Atlas Energy also competes with a number of other companies that offer interests in investment partnerships. As a result, competition for investment capital to fund investment partnerships is intense.

Atlas Pipeline Holdings

Acquisitions. APL has recently encountered competition in acquiring midstream assets owned by third parties. In several instances, APL submitted bids in auction situations and in direct negotiations for the acquisition of such assets and was either outbid by others or was unwilling to meet the sellers' expectations. In the future, APL expects 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 APL's Mid-Continent service area, it competes 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. APL believes 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.

APL believes that its relationships with operators connected to its system are good and that it presents an attractive alternative for producers. However, if APL cannot compete successfully, it may be unable to obtain new well connections and, possibly, could lose wells already connected to its 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. APL's 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 APL's Appalachian Basin operations principally serve wells drilled by Atlas Energy, APL is affected by competitive factors affecting Atlas Energy's ability to obtain properties and drill wells, which affects APL's ability to expand its gathering systems and to maintain or increase the volume of natural gas APL transports and, thus, its 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 APL's gathering systems. These delays would reduce the volume of natural gas APL otherwise would have transported, thus reducing its potential transportation revenues.

As the omnibus agreement with Atlas Energy generally requires APL to connect wells Atlas Energy operates to APL's system, APL does not expect any direct competition in connecting wells drilled and operated by Atlas Energy in the future. In addition, APL occasionally connects wells operated by third parties. For the year ended December 31, 2006, APL connected 26 third party wells.

Markets

The availability of a ready market for natural gas and oil and the price obtained, depends upon numerous factors beyond our control, as described in "Risk factors—Risks Relating in Our Business." Product availability and price are the principal means of competition in selling oil and natural gas. During the three years ended December 31, 2006, neither Atlas Energy nor Atlas Pipeline experienced problems in selling their natural gas, oil, or NGLs although prices have varied significantly during those periods.

Contracts and Customer Relationships

In its Mid-Continent operations, APL either purchases natural gas from producers, or intermediaries, and moves the natural gas into receipt points on its systems and then sells the natural gas, and produced natural gas liquids ("NGLs"), if any, off of delivery points on its systems, or APL transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Beyond the distinction of purchasing or transporting natural gas, APL has a variety of contractual relationships with its 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, APL provides gathering, compression, treating and dehydration services to its 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, APL purchases natural gas at the wellhead, processes the natural gas and sells the plant residue natural gas and NGLs at market-based prices, remitting to producers a percentage of the proceeds. Under keep-whole contracts, APL gathers natural gas from the producer, processes the natural gas and sells 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, APL must replace these Btus by either purchasing natural gas at market prices or making a cash payment to the producer. APL's profitability is dependent upon the spread between the price of natural gas, its feedstock, and NGLs, its "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 APL transports in its Appalachian operations is under a percentage-of-proceeds contract with Atlas Energy where APL calculates its transportation fee as a percentage of the price of the natural gas it transports. The natural gas APL transports in its Appalachian operations does not require processing.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit Atlas Energy's drilling and producing activities and other operations in certain areas of the Appalachian region. These seasonal anomalies may pose challenges for meeting its well construction objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay its operations. In the past, we have drilled a greater number of wells during the winter months due to the fact that we have typically received the majority of funds from our investment partnerships during the fourth calendar quarter. Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation

Atlas Energy

Atlas Energy's operations are subject to comprehensive and stringent federal, state and local laws and regulations governing, among other things, where and how it installs wells, how it handles wastes from its operations and the discharge of materials into the environment. Atlas Energy's operations are subject to the same environmental laws and regulations as other companies in the natural gas and oil industry. Among other requirements and restrictions, these laws and regulations:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within or, in some cases, adjoining wilderness, wetlands and other protected areas;
- require remedial measures to reduce, mitigate or respond to releases of pollutants or hazardous substances from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently enact new, and revise existing, environmental laws and regulations, and any new laws or changes to existing laws that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs. We believe that Atlas Energy's operations on the whole substantially comply with all currently applicable environmental laws and regulations and that its continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict how environmental laws and regulations that may take effect in the future may impact its properties or operations. For the years ended December 31, 2006 and 2005, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures in 2007, or that will otherwise have a material impact on our financial position or results of operations.

Environmental laws and regulations that could have a material impact on the natural gas and oil exploration and production industry include the following:

National Environmental Policy Act. Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will typically require an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that will be made available for public review and comment. All of our proposed exploration and production activities on federal lands require governmental permits, many of which are subject to the requirements of NEPA. This process has the potential to delay the development of natural gas and oil projects.

Waste Handling. The Solid Waste Disposal Act, including the Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and the disposal of non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil and natural gas constitute "solid wastes", which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation.

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

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "Superfund" law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered under the statute to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Atlas Energy's operations are, in many cases, conducted at properties that have been used for natural gas and oil exploitation and production for many years. Although we believe we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons 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, Atlas Energy could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The Clean Water Act also requires specified facilities to maintain and implement spill prevention, control and countermeasure plans and to take measures to minimize the risks of petroleum spills. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for failure to obtain or non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe our operations on the whole are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. The Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through permits and other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic and other air pollutants at specified sources. Some of Atlas Energy's new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new emission limitations. These regulations may increase the costs of compliance for some facilities, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of compliance of Atlas Energy's customers to the point where demand for natural gas is affected. We believe that Atlas Energy's operations are in substantial compliance with the requirements of the Clean Air Act.

OSHA and Other Regulations. Atlas Energy is subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that Atlas Energy's organize and/or disclose information about hazardous materials used or produced in our operations. We believe that Atlas Energy is in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Other Laws and Regulation. The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The natural gas and oil industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Atlas Energy's operations are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact its business.

Other Regulations. The natural gas and oil industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases Atlas Energy's cost of doing business and, consequently, affects our profitability, these burdens generally do not affect Atlas Energy any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Atlas Energy's operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs Atlas Energy could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production. Atlas Energy's operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which Atlas Energy operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and

- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil Atlas Energy can produce from its wells or limit the number of wells or the locations at which it can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Natural Gas Regulation. The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

State Regulation. The various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Tennessee currently imposes a 3% severance tax on natural gas and oil production and Ohio imposes a severance tax of $0.025 per mcf of natural gas and $0.10 per barrel of oil. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from Atlas Energy’s wells, and to limit the number of wells or locations it can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon us.

Atlas Pipeline

Regulation by FERC of Interstate Natural Gas Pipelines. FERC regulates APL’s 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 APL’s 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 APL's 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. APL owns 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 APL's 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 APL's gathering systems for public safety purposes. APL's operating subsidiary has been granted an exemption by the Public Utilities Commission of Ohio for APL's 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. APL's gas gathering operations currently are not subject to regulation by the New York Public Service Commission. APL's 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, APL's 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 APL's operations, we believe that APL's operating costs could increase and its transportation fees could be adversely affected, thereby reducing APL's net revenues and its ability to make distributions to its general partner and common unitholders.

APL is 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 APL's right as an owner of gathering facilities to decide with whom it contracts 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 APL's 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. APL's 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.

APL's 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 APL's 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 APL's 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 APL's 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 APL will be affected by any such FERC action materially differently than other companies with whom APL competes.

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 APL's 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, APL must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact APL's business activities in many ways, such as:

- restricting the way APL can handle or dispose of its 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 APL's 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 APL's 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 APL's 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 APL to incur significant costs.

Hazardous Waste. APL's 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. CERCLA, 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 its ordinary operations APL 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, APL 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.

APL currently owns or leases, 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 APL 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 APL 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 APL. 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 APL's control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, APL 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. APL's operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including APL's processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that APL obtains 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. APL's failure to comply with these requirements could subject it to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. APL 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 APL's operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to APL than to any other similarly situated companies.

Pipeline Safety. APL's 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 APL's 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 APL's operations but there is no assurance that this trend will continue in the future.

Employee Health and Safety. APL is subject to the requirements of the 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 APL's 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 APL's Velma gas plant contains high levels of hydrogen sulfide, and APL employs numerous safety precautions at the system to ensure the safety of its employees. There are various federal and state environmental and safety requirements for handling sour gas, and APL is in substantial compliance with all such requirements.

Litigation

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, including spills of oil or releases of pollutants, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings pending against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject as to which specific disclosure would be required under the securities laws.

Credit Facilities

The Company

Our revolving credit facility terminated in December 2006 with the transfer of substantially all of our natural gas and oil production assets to Atlas Energy. Simultaneously, Atlas Energy entered into a revolving credit facility, described below, secured by those assets. We are currently negotiating a new credit facility with Wachovia Bank, National Association.

Atlas Energy

Simultaneously with the completion of its initial public offering, Atlas Energy entered into a $250 million senior secured credit facility with Wachovia Bank, National Association, as administrative agent, Wachovia Capital Markets LLC, as lead arranger, and other lenders. The credit facility allows the Atlas Energy to borrow up to the determined amount of the borrowing base, which will be based upon the loan collateral value assigned to its various natural gas and oil properties. The initial borrowing base is $155 million. The borrowing base will be subject to redetermination on March 14, 2007 and on a semi-annual basis thereafter. The credit facility will mature on December 18, 2011.

Atlas Energy's obligations under the credit facility are secured by mortgages on its natural gas and oil properties as well as a pledge of all of its ownership interests in its operating subsidiaries, other than Anthem Securities. Atlas Energy will be required to maintain the mortgages on properties representing at least 80% of its natural gas and oil properties. Additionally, the obligations under the credit facility are guaranteed by all of Atlas Energy's existing operating subsidiaries and by any future subsidiaries, other than Anthem Securities. Borrowings under the credit facility will be available for development, exploitation and acquisition of natural gas and oil properties, working capital and general corporate purposes.

At Atlas Energy's election, interest will be determined by reference to:

- the London interbank offered rate, or LIBOR, plus an applicable margin between 1.00% and 1.75% per annum, depending on its usage of the facility; or
- the higher of (i) the federal funds rate plus 0.50% or (ii) the Wachovia prime rate, plus, in each case, an applicable margin between 0.00% and 0.75% per annum, depending on its usage of the facility.

Interest will generally be payable quarterly for domestic bank rate loans and at the end of each applicable interest period for LIBOR loans.

The credit facility contains customary covenants that, among other things, limit Atlas Energy's ability to incur indebtedness; make certain loans, acquisitions, capital expenditures and investments; enter into hedging arrangements that exceed 85% of its proved reserves; make any change to the character of its business or the business of the investment partnerships; or engage in certain asset dispositions, including a sale of all or substantially all of its assets.

The credit facility requires Atlas Energy to maintain a current ratio (defined as the ratio of current assets to current liabilities) of not less than 1.0 to 1.0; a funded debt to EBITDA ratio of not more than 3.5 to 1.0; and a minimum interest coverage ratio (defined as our EBITDA divided by our interest expense) of not less than 2.5 to 1.0. The credit facility defines EBITDA for any period of four fiscal quarters as the sum of consolidated net income for the period plus interest, income taxes, depreciation, depletion and amortization.

If an event of default exists under the credit facility, the lenders will be able to accelerate the maturity of the credit facility and exercise other customary rights and remedies, including prohibiting Atlas Energy from paying distributions.

Atlas Pipeline Holdings

Atlas Pipeline Holdings has a $50.0 million revolving credit facility with Wachovia Bank, National Association, as administrative agent and issuing bank, and a syndicate of banks. AHD's credit facility matures in April 2010 and bears interest, at its option, at either (i) adjusted LIBOR (as defined in its credit facility) or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank, National Association prime rate, except that no more than five LIBOR loans may be outstanding at any time. Borrowings under this credit facility are secured by a first-priority lien on a security interest in all of its assets, including a pledge of Atlas Pipeline GP's interests in APL, and are guaranteed by Atlas Pipeline GP and its other subsidiaries (excluding APL and its subsidiaries). AHD's credit facility contains customary covenants, including restrictions on its ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists or would result from such distribution; or enter into a merger or sale of substantially all of its property or assets, including the sale or transfer of interests in its subsidiaries. AHD is in compliance with these covenants as of December 31, 2006.

The events which constitute an event of default under AHD'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 it in excess of a specified amount, a change of control of Atlas America, AHD's general partner or any other obligor, and termination of a material agreement and occurrence of a material adverse effect.

AHD's credit facility requires it to maintain a combined leverage ratio (defined as the ratio of the sum of (i) its funded debt (as defined in its credit facility) and (ii) APL's funded debt (as defined in APL's credit facility) to APL's EBITDA (as defined in APL's credit facility)) of not more than 5.5 to 1.0. In addition, AHD's credit facility requires it to maintain a funded debt (as defined in its credit facility) to EBITDA ratio of not more than 3.5 to 1.0; and an interest coverage ratio (as defined in its credit facility) of not less than 3.0 to 1.0. AHD's credit facility defines EBITDA for any period of four quarters as the sum of (i) four times the amount of cash distributions payable by APL to AHD in respect of its general partner interest, limited partner interest and incentive distribution rights in APL with respect to the last quarter in such period, and (ii) AHD's consolidated net income (as defined in its credit facility and as adjusted as provided in its credit facility). As of December 31, 2006, AHD's combined leverage ratio was 3.8 to 1.0, and it was in compliance with its funded debt and interest coverage ratio as it had no borrowings during the compliance period.

AHD may borrow under its credit facility (i) for general business purposes, including for working capital, to purchase debt or limited partnership units of APL, to fund general partner contributions from AHD to APL and to make permitted acquisitions, (ii) to pay fees and expenses related to its credit facility and (iii) for letters of credit.

Atlas Pipeline

APL has a $225.0 million credit facility with a syndicate of banks which matures in June 2011. APL's credit facility bears interest, at its 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 APL's outstanding credit facility borrowings at December 31, 2006 was 7.6%. Up to $50.0 million of APL's 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 APL's credit facility are secured by a lien on and security interest in all of APL's property and that of its wholly-owned subsidiaries, and by the guaranty of each of its wholly-owned subsidiaries. APL's credit facility contains customary covenants, including restrictions on its 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. APL is 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 APL's credit agreement, adverse judgments against APL in excess of a specified amount, and a change of control of APL's general partner.

APL's credit facility requires it to maintain a ratio of senior secured debt (as defined in its credit facility) to EBITDA (as defined in its credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in its credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in its credit facility) of not less than 3.0 to 1.0. APL's credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of December 31, 2006, APL's ratio of senior secured debt to EBITDA was 0.5 to 1.0, its funded debt ratio was 3.8 to 1.0 and its interest coverage ratio was 3.8 to 1.0.

Employees

As of December 31, 2006, we employed 517 persons.

Available Information

You may receive, without charge, a paper copy of our annual report on Form 10-K, our quarterly reports on Form 10-Q and our current reports on Form 8-K, 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 450 Fifth Street, N.W., Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information. Our site is www.atlasamerica.com.

ITEM 1A: RISK FACTORS

Statements made by us in written or oral form to various persons, including statements made in filings with the SEC that are not strictly historical facts, are "forward-looking" statements that are based on current expectations about our business and assumptions made by management. These statements are subject to risks and uncertainties that exist in our operations and business environment that could result in actual outcomes and results that are materially different than predicted. The following includes some, but not all, of those factors or uncertainties:

Risks Relating to Our Business

We are required to pay gathering fees to Atlas Pipeline pursuant to our contribution agreement with Atlas Energy equal to the difference between the gathering fee payable and the amount Atlas Energy receives from its investment partnerships for gathering services out of our own resources. Under our contribution agreement with Atlas Energy, we assumed Atlas Energy's obligation to pay gathering fees to Atlas Pipeline pursuant to the master natural gas gathering agreement, and Atlas Energy agreed to pay us the gathering fees it receives from its investment partnerships and fees associated with production to its interest. The gathering fees payable to Atlas Pipeline generally exceed the amount Atlas Energy receives from its investment partnerships for gathering services. For the twelve months ended December 31, 2006, this excess amount was approximately $30.3 million.

We may be required to indemnify Atlas Energy for claims relating to activities before our contribution of assets to it. Pursuant to our contribution agreement with Atlas Energy, we will indemnify Atlas Energy until December 18, 2007 against certain potential environmental liabilities associated with the operation of the assets we contributed to it and occurring before December 18, 2006 and against claims for covered environmental liabilities made before December 18, 2010. Our obligation will not exceed $25.0 million, and we will not have any indemnification obligation until Atlas Energy's losses exceed $500,000 in the aggregate, and then only to the extent such aggregate losses exceed $500,000. Additionally, we will indemnify Atlas Energy for losses attributable to title defects to the oil and gas property interests until December 18, 2009, and indefinitely for losses attributable to retained liabilities and income taxes attributable to pre-closing operations and the formation transactions.

We could be liable for taxes in connection with our spin-off from Resource America. In connection with our initial public offering, Resource America and we entered into a tax matters agreement which governs our respective rights, responsibilities, and obligations with respect to tax liabilities and benefits. In general, under the tax matters agreement:

- Resource America is responsible for any U.S. federal income taxes of the affiliated group for U.S. federal income tax purposes of which Resource America is the common parent. With respect to any periods beginning after our initial offering, we are responsible for any U.S. federal income taxes attributable to us or any of our subsidiaries.
- Resource America is responsible for any U.S. state or local income taxes reportable on a consolidated, combined or unitary return that includes Resource America or one of its subsidiaries, on the one hand, and us or one of our subsidiaries, on the other hand. However, in the event that we or one of our subsidiaries are included in such a group for U.S. state or local income tax purposes for periods (or portions thereof) beginning after the date of the initial public offering, we are responsible for our portion of such income tax liability as if we and our subsidiaries had filed a separate tax return that included only us and our subsidiaries for that period (or portion of a period).
- Resource America is responsible for any U.S. state or local income taxes reportable on returns that include only Resource America and its subsidiaries (excluding us and our subsidiaries), and we are responsible for any U.S. state or local income taxes filed on returns that include only us and our subsidiaries.

- Resource America is responsible for any U.S. state or local income taxes reportable on returns that include only Resource America and its subsidiaries (excluding us and our subsidiaries), and we are responsible for any U.S. state or local income taxes filed on returns that include only us and our subsidiaries.

Risks Related to Atlas Energy

Atlas Energy may not have sufficient cash flow from operations to pay the initial quarterly distribution, or IQD, to us following the establishment of cash reserves and payment of fees and expenses. Atlas Energy may not have sufficient cash flow from operations each quarter to pay the IQD of $0.42. Under the terms of its limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by its operating expenses and the amount of any cash reserve amounts that its board of directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders and the holders of the management incentive interests. The amount of cash it can distribute principally depends upon the amount of cash it generate from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas and oil it produces;
- the price at which it sells its natural gas and oil;
- the level of its operating costs;
- its ability to acquire, locate and produce new reserves;
- results of its hedging activities;
- the level of its interest expense, which depends on the amount of its indebtedness and the interest payable on it; and
- the level of its capital expenditures.

In addition, the actual amount of cash we will receive from its distributions will depend on other factors, some of which are beyond its control, including:

- its ability to make working capital borrowings to pay distributions;
- the cost of acquisitions, if any;
- fluctuations in its working capital needs;
- timing and collectibility of receivables;
- restrictions on distributions imposed by lenders;
- the amount of its estimated maintenance capital expenditures;
- prevailing economic conditions; and
- the amount of cash reserves established by its board of directors for the proper conduct of its business.

As a result of these factors, the amount of cash Atlas Energy distributes in any quarter to us may fluctuate significantly from quarter to quarter and may be significantly less than the IQD amount that we expect to receive.

If commodity prices decline significantly, Atlas Energy's cash flow from operations will decline and it may have to lower its distributions or may not be able to pay distributions at all. Atlas Energy's revenue, profitability and cash flow substantially depend upon the prices and demand for natural gas and oil. The natural gas and oil markets are very volatile and a drop in prices can significantly affect its financial results and impede its growth. Changes in natural gas and oil prices will have a significant impact on the value of its reserves and on its cash flow. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas or oil, market uncertainty and a variety of additional factors that are beyond its control, such as:

- the level of the domestic and foreign supply and demand;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions and fluctuating and seasonal demand;
- overall domestic and global economic conditions;
- political and economic conditions in natural gas and oil producing countries, including those in the Middle East and South America;

- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the impact of the U.S. dollar exchange rates on natural gas and oil prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental relations, regulations and taxation;
- the impact of energy conservation efforts;
- the cost, proximity and capacity of natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, the prices of natural gas and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2006, the NYMEX Henry Hub natural gas index price ranged from a high of $11.43 per MMBtu to a low of $4.20 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $75.92 per Bbl to a low of $56.93 per Bbl.

At December 31, 2006, Atlas Energy owned interests in 7,252 gross wells. Producers with higher rates of production than Atlas Energy's are less sensitive to declining commodity prices due to the relatively fixed nature of well operating costs. Lower natural gas and oil prices may not only decrease Atlas Energy's revenues, but also reduce the amount of natural gas and oil that it can produce economically, which would also decrease its revenues and cause it to shut in, and eventually plug and abandon, uneconomic wells.

Unless Atlas Energy replaces its reserves, its reserves and production will decline, which would reduce its cash flow from operations and impair its ability to make distributions to us. Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Based on Atlas Energy's December 31, 2006 reserve report, its average annual decline rate for proved developed producing reserves is approximately 12% during the first five years, approximately 7% in the next five years and less than 6% thereafter. Because total estimated proved reserves include proved undeveloped reserves at December 31, 2006, production will decline at this rate even if those proved undeveloped reserves are developed and the wells produce as expected. This rate of decline will change if production from Atlas Energy's existing wells declines in a different manner than it has estimated and can change when it drills additional wells, makes acquisitions and under other circumstances. Thus, Atlas Energy's future natural gas reserves and production and, therefore, its cash flow and income are highly dependent on its success in efficiently developing and exploiting its current reserves and economically finding or acquiring additional recoverable reserves. Atlas Energy's ability to find and acquire additional recoverable reserves to replace current and future production at acceptable costs depends on its generating sufficient cash flow from operations and other sources of capital, principally its sponsored investment partnerships, all of which are subject to the risks discussed elsewhere in this section.

*Atlas Energy's estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of its reserves. U*nderground accumulations of natural gas and oil cannot be measured in an exact way. Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Atlas Energy's independent petroleum engineers prepare estimates of its proved reserves. Over time, its internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of its reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, it makes certain assumptions regarding future natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect its estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Atlas Energy's PV-10 is calculated using natural gas prices that include its physical hedges but not its financial hedges. Numerous changes over time to the assumptions on which its reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil it ultimately recover being different from its reserve estimates.

The present value of future net cash flows from Atlas Energy's proved reserves is not necessarily the same as the current market value of its estimated natural gas reserves. Atlas Energy bases the estimated discounted future net cash flows from its proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from its natural gas properties also will be affected by factors such as:

- actual prices it receive for natural gas;

- the amount and timing of actual production;
- the amount and timing of its capital expenditures;
- supply of and demand for natural gas; and
- changes in governmental regulations or taxation.

The timing of both its production and its incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor it uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with it or the natural gas and oil industry in general.

Any significant variance in its assumptions could materially affect the quantity and value of reserves, the amount of PV-10, and its financial condition and results of operations. In addition, its reserves or PV-10 may be revised downward or upward based upon production history, results of future exploitation and development activities, prevailing natural gas and oil prices and other factors. A material decline in prices paid for its production can reduce the estimated volumes of its reserves because the economic life of its wells could end sooner. Similarly, a decline in market prices for natural gas or oil may reduce its PV-10. Any of these negative effects on its reserves or PV-10 may decrease the value of our investment in it.

Atlas Energy's operations require substantial capital expenditures, which will reduce its cash available for distribution. In addition, each quarter it is required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available to us than if actual maintenance capital expenditures were deducted. Atlas Energy will need to make substantial capital expenditures to maintain its capital asset base over the long term. For the twelve months ending December 31, 2007, we estimate these expenditures to be approximately $35.0 million. These maintenance capital expenditures may include the drilling and completion of additional wells to offset the production decline from its producing properties or additions to its inventory of unproved or proved reserves. These expenditures could increase as a result of:

- changes in its reserves;
- changes in natural gas prices;
- changes in labor and drilling costs;
- its ability to acquire, locate and produce reserves;
- changes in leasehold acquisition costs; and
- government regulations relating to safety and the environment.

Atlas Energy's significant maintenance capital expenditures will reduce the amount of cash it has available for distribution to us. In addition, its actual maintenance capital expenditures will vary from quarter to quarter. Its limited liability company agreement requires it to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and approval by its board of directors, including a majority of its conflicts committee, at least once a year. In years when its estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to us will be lower than if it deducted actual maintenance capital expenditures from operating surplus. If it underestimates the appropriate level of estimated maintenance capital expenditures, it may have less cash available for distribution in future periods when actual capital expenditures begin to exceed its previous estimates. Over time, if it does not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain its capital asset base, it will be unable to pay distributions at the anticipated level and may have to reduce its distributions.

Atlas Energy will be required to make substantial capital expenditures to increase its asset base. If it is unable to obtain needed capital or financing on satisfactory terms, its ability to make cash distributions may be diminished. The natural gas and oil industry is capital intensive. Atlas Energy intends to finance its future capital expenditures with capital raised through its sponsored investment partnerships, cash flow from operations and bank borrowings. If it is unable to obtain sufficient capital funds on satisfactory terms, it may be unable to increase or maintain our inventory of properties and reserve base, or be forced to curtail drilling or other activities. This would result in a decline in its revenues and its ability to increase cash distributions may be diminished. If it does not make sufficient or effective expansion capital expenditures, including with funds from third-party sources, it will be unable to expand its business operations and will be unable to raise the level of its future cash distributions.

Changes in tax laws may impair Atlas Energy's ability to obtain capital funds through investment partnerships. Under current federal tax laws, there are tax benefits to investing in investment partnerships such as those Atlas Energy sponsors, including deductions for intangible drilling costs and depletion deductions. Changes to federal tax law that reduce or eliminate these benefits may make investment in its investment partnerships less attractive and, thus, reduce its ability to obtain funding from this significant source of capital funds. A recent change to federal tax law that may affect it is the Jobs and Growth Tax Relief Reconciliation Act of 2003, which reduced the maximum federal income tax rate on long-term capital gains and qualifying dividends to 15% through 2008. These changes may make investment in its investment partnerships relatively less attractive than investments in assets likely to yield capital gains or qualifying dividends.

Atlas Energy's credit facility has substantial restrictions and financial covenants. A default under these provisions could cause all of its debt to be immediately due and restrict its payment of distributions to us. Atlas Energy's revolving credit facility restricts its ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. Atlas Energy is also required to comply with specified financial covenants and ratios. Its ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from its operations and events or circumstances beyond its control. Atlas Energy's failure to comply with any of the restrictions and covenants under the credit facility could result in a default, which could cause its existing indebtedness to be immediately due and restrict its payment of distributions to us.

Atlas Energy's future debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities. Atlas Energy's future indebtedness could have important consequences to it, including:

- its ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in its credit arrangements will require it to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;
- Atlas Energy will need a substantial portion of its cash flow to make principal and interest payments on its indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to us; and
- Atlas Energy's debt level will make it more vulnerable than its competitors with less debt to competitive pressures or a downturn in its business or the economy generally.

Atlas Energy's ability to service its indebtedness will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond its control. If its operating results are not sufficient to service its current or future indebtedness, it 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 its indebtedness, or seeking additional equity capital or bankruptcy protection. Atlas Energy may not be able to affect any of these remedies on satisfactory terms or at all.

Atlas Energy may not be able to continue to raise funds through its investment partnerships at the levels it has recently experienced, which may in turn restrict its ability to maintain its drilling activity at the levels recently experienced. Atlas Energy has sponsored limited and general partnerships to raise funds from investors to finance its development drilling activities. Accordingly, the amount of development activities it undertakes depends in large part upon its ability to obtain investor subscriptions to invest in these partnerships. During the past three fiscal years Atlas Energy has raised successively larger amounts of funds through these investment partnerships, raising $107.7 million in 2004, $148.7 million in 2005 and $218.5 million in 2006. In the future, it may not be successful in raising funds through these investment partnerships at the same levels it has recently experienced, and it also may not be successful in increasing the amount of funds it raises as it has done in recent years. Atlas Energy's ability to raise funds through its investment partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by its historical track record of generating returns and tax benefits to the investors in our existing partnerships.

In the event that Atlas Energy's investment partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, Atlas Energy may have difficulty in continuing to increase the amount of funds it raises through these partnerships or in maintaining the level of funds it has recently raised through these partnerships. In this event, it may need to obtain financing for its drilling activities on a less attractive basis than the financing it realizes through these partnerships or it may determine to reduce its drilling activity.

Competition in the natural gas and oil industry is intense, which may hinder Atlas Energy's ability to acquire gas and oil properties and companies and to obtain capital, contract for drilling equipment and secure trained personnel. Atlas

Energy operates in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through its investment partnerships, contracting for drilling equipment and securing trained personnel. Atlas Energy will also compete with the exploration and production divisions of public utility companies for natural gas and oil property acquisitions. Atlas Energy's competitors may be able to pay more for natural gas and oil properties and drilling equipment and to evaluate, bid for and purchase a greater number of properties than its financial or personnel resources permit. Moreover, its competitors for investment capital may have better track records in their programs, lower costs or better connections in the securities industry segment that markets oil and gas investment programs than it does. All of these challenges could make it more difficult for Atlas Energy to execute its growth strategy. Atlas Energy may not be able to compete successfully in the future in acquiring leasehold acreage or prospective reserves or in raising additional capital.

Furthermore, competition arises not only from numerous domestic and foreign sources of natural gas and oil but also from other industries that supply alternative sources of energy. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Product availability and price are the principal means of competition in selling oil and natural gas. Many of Atlas Energy's competitors possess greater financial and other resources than it which may enable them to identify and acquire desirable properties and market their natural gas and oil production more effectively than it does.

Atlas Energy's business depends on the gathering and transportation facilities of Atlas Pipeline. Any limitation in the availability of those facilities would interfere with its ability to market the natural gas it produces and could reduce its revenues and cash available for distribution to us. Atlas Pipeline gathers more than 90% of Atlas Energy's current production. The marketability of its natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by Atlas Pipeline and other third parties. The amount of natural gas that can be produced and sold is subject to curtailment in circumstances such as pipeline interruptions due to scheduled and unscheduled maintenance or excessive pressure or physical damage to the gathering or transportation system. The curtailments arising from these and similar circumstances may last from a few days to several months.

Atlas Energy depends on certain key customers for sales of its natural gas. To the extent these customers reduce the volumes of natural gas they purchase from it, its revenues and cash available for distribution to us could decline. Atlas Energy's natural gas is sold under contracts with various purchasers. Under a natural gas supply agreement with Hess Corporation, which expires on March 31, 2009, Hess Corporation has a last right of refusal to buy all of the natural gas produced and delivered by Atlas Energy and its affiliates, including its investment partnerships. During the year ended December 31, 2006, total sales to Hess Corp accounted for 3% of our total revenues, respectively. To the extent Hess Corporation and Atlas Energy's other key customers reduce the amount of natural gas they purchase from Atlas Energy, its revenues and cash available for distributions to us could temporarily decline in the event it is unable to sell to additional purchasers.

Shortages of drilling rigs, equipment and crews could delay Atlas Energy's operations and reduce its cash available for distribution to us. Higher natural gas and oil prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the past three years, we and other oil and natural gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict Atlas Energy's ability to drill the wells and conduct the operations which it currently has planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce its revenues and cash available for distribution to us.

Because Atlas Energy handles natural gas and oil, it may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment. The operations of Atlas Energy's wells and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. 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, including the RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of 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 hazardous substances or other waste products into the environment.

Drilling for and producing natural gas are high risk activities with many uncertainties. Atlas Energy's drilling activities are subject to many risks, including the risk that it will not discover commercially productive reservoirs. Drilling for natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, its drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- formations with abnormal pressures;
- injury or loss of life;
- environmental accidents such as gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment or oil leaks, including groundwater contamination;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of natural gas or well fluids.

Any one or more of the factors discussed above could reduce or delay Atlas Energy's receipt of drilling and production revenues, thereby reducing its earnings, and could reduce revenues in one or more of its investment partnerships, which may make it more difficult to finance its drilling operations through sponsorship of future partnerships. In addition, any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

Although Atlas Energy will maintain insurance against various losses and liabilities arising from its operations, insurance against all operational risks is not available to it. Additionally, it may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could reduce Atlas Energy's results of operations and impair its ability to make distributions to us.

Properties that Atlas Energy buys may not produce as projected and it may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities. One of Atlas Energy's growth strategies is to capitalize on opportunistic acquisitions of natural gas reserves. However, its reviews of acquired properties are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when Atlas Energy inspects a well. Any unidentified problems could result in material liabilities and costs that negatively impact Atlas Energy's financial condition and results of operations.

Even if Atlas Energy is able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity.

Hedging transactions may limit Atlas Energy's potential gains or cause us to lose money. By removing the price volatility from a significant portion of its natural gas production, Atlas Energy has reduced, but not eliminated, the potential effects of changing natural gas prices on its cash flow from operations for those periods. Furthermore, while intended to help reduce the effects of volatile natural gas prices, such transactions, depending on the hedging instrument used, may limit its potential gains if natural gas prices were to rise substantially over the price established by the hedge. Under circumstances in which, among other things, production is substantially less than expected, the counterparties to its futures contracts fail to perform under the contracts or a sudden, unexpected event materially impacts natural gas prices, it may be exposed to the risk of financial loss.

Atlas Energy may be exposed to financial and other liabilities as the managing general partner in investment partnerships. Atlas Energy serves as the managing general partner of 92 investment partnerships and will be the managing general partner of new investment partnerships that it sponsors. As a general partner, it is contingently liable for the obligations of these partnerships to the extent that partnership assets or insurance proceeds are insufficient. Atlas Energy has agreed to indemnify each investor partner in its investment partnerships from any liability that exceeds such partner's share of the investment partnership's assets. Furthermore, investor partners in some of its investment partnerships have the right to present their interests for purchase by it, as managing general partner, up to 5% to 10% of the total limited partner interests in any calendar year.

Atlas Energy's revenues may decrease if investors in its investment partnerships do not receive a minimum return. Atlas Energy has agreed to subordinate up to 50% of its share of production revenues to specified returns to the investor partners in our investment partnerships, typically 10% per year for the first five years of distributions. Thus, Atlas Energy's revenues from a particular partnership will decrease if it does not achieve the specified minimum return and its ability to make distributions to us may be impaired.

Risks Related to Atlas Pipeline Holdings

AHD's only cash generating assets are its interests in APL, and its cash flow is therefore completely dependent upon the ability of APL to make distributions to its partners. The amounts of cash that APL generates may not be sufficient for it to pay distributions at the current or any other level of distribution. APL's ability to make cash distributions depends primarily on its cash flow. Cash distributions do not depend directly on APL's profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when APL records losses and may not be made during periods when APL records profits. The actual amounts of cash APL generates will depend upon numerous factors relating to its business which may be beyond its control, including:

- the demand for and price of its natural gas and NGLs;
- expiration of significant contracts;
- the volume of natural gas APL transports;
- continued development of wells for connection to APL's gathering systems;
- the availability of local, intrastate and interstate transportation systems;
- the expenses APL incurs in providing its gathering services;
- the cost of acquisitions and capital improvements;
- APL's issuance of equity securities;
- required principal and interest payments on APL's 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 APL will have available for distribution will depend on other factors, including:

- the level of capital expenditures it makes;
- the sources of cash used to fund its acquisitions;
- its debt service requirements and requirements to pay dividends on its outstanding preferred units, and restrictions on distributions contained in its current or future debt agreements; and
- the amount of cash reserves established by us, as APL's general partner, for the conduct of APL's business.

APL 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" under its partnership agreement. Because APL will be unable to borrow money to pay distributions unless it establishes a facility that meets the definition contained in its partnership agreement, APL's ability to pay a distribution in any quarter is solely dependent on its ability to generate sufficient operating surplus with respect to that quarter.

APL's debt levels and restrictions in AHD's and APL's credit facilities could limit AHD's ability to make distributions to us. APL has a significant amount of debt. APL will need a substantial portion of its cash flow to make principal and interest payments on its indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to its unitholders. If APL's operating results are not sufficient to service its current or future indebtedness, it 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 its indebtedness, or seeking additional equity capital or bankruptcy protection. APL may not be able to affect any of these remedies on satisfactory terms, or at all.

AHD's and APL's credit facilities contain covenants limiting their ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to unitholders. AHD's and APL's credit facilities also contain covenants requiring APL and AHD to maintain certain financial ratios. In addition, AHD and APL are prohibited from making any distribution if such distribution would cause an event of default or otherwise violate a covenant under their respective credit facilities.

In the future, AHD may not have sufficient cash to pay distributions at its current quarterly distribution level or to increase distributions. The source of AHD's earnings and cash flow currently consists exclusively of cash distributions from APL. Therefore, the amount of distributions it is able to make to us may fluctuate based on the level of distributions APL makes to its partners. In addition, while AHD would expect to increase or decrease distributions to us if APL increases or decreases distributions to AHD, the timing and amount of such increased or decreased distributions, if any, will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by APL to AHD.

AHD's ability to distribute cash received from APL to us is limited by a number of factors, including:

- interest expense and principal payments on any current or future indebtedness;
- restrictions on distributions contained in any current or future debt agreements;
- AHD's general and administrative expenses, including expenses is incurs as a result of being a public company;
- expenses of AHD's subsidiaries other than APL, including tax liabilities of its corporate subsidiaries, if any;
- reserves necessary for AHD to make the necessary capital contributions to maintain its 2.0% general partner interest in APL as required by its partnership agreement upon the issuance of additional partnership securities by APL; and
- reserves AHD's general partner believes prudent for it to maintain for the proper conduct of its business or to provide for future distributions.

The actual amount of cash that is available for distribution to us will depend on numerous factors, many of which are beyond its control or the control of AHD's general partner.

A reduction in APL's distributions will disproportionately affect the amount of cash distributions to which AHD is currently entitled. AHD's ownership of the incentive distribution rights in APL, through its ownership of equity interests in Atlas Pipeline GP, the holder of the incentive distribution rights, entitles it to receive its pro rata share of specified percentages of total cash distributions made by APL with respect to any particular quarter only in the event that APL distributes more than $0.42 per common unit for such quarter. As a result, the holders of APL's common units have a priority over the holders of APL's incentive distribution rights to the extent of cash distributions by APL up to and including $0.42 per common unit for any quarter.

A decrease in the amount of distributions by APL to less than $0.60 per common unit per quarter would reduce Atlas Pipeline GP's percentage of the incremental cash distributions above $0.52 per common unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from APL would have the effect of disproportionately reducing the amount of all distributions that AHD receives based on its ownership interest in the incentive distribution rights in APL as compared to cash distributions it receives on its 2.0% general partner interest in APL and its APL common units.

AHD's ability to meet its financial needs may be adversely affected by its cash distribution policy and its lack of operational assets. AHD's cash distribution policy, which is consistent with its partnership agreement, requires it to distribute all of its available cash quarterly. AHD's only cash generating assets are partnership interests, including incentive distribution rights, in APL, and it currently has no independent operations separate from those of APL. Moreover, a reduction in APL's distributions will disproportionately affect the amount of cash distributions AHD receives. Given that its cash distribution policy is to distribute available cash and not retain it and that its only cash generating assets are partnership interests in APL, it may not have enough cash to meet its needs if any of the following events occur:

- an increase in its operating expenses;
- an increase in general and administrative expenses;
- an increase in principal and interest payments on its outstanding debt;
- an increase in working capital requirements; or
- an increase in cash needs of APL or its subsidiaries that reduces APL's distributions.

AHD's cash distribution policy limits its ability to grow. Because AHD distributes all of its available cash, its growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. In fact, its growth initially will be completely dependent upon APL's ability to increase its quarterly distribution per unit because currently its only cash-generating assets are partnership interests in APL, including incentive distribution rights. If AHD issues additional units or incurs debt to fund acquisitions and capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that AHD will be unable to maintain or increase its per unit distribution level.

Consistent with the terms of its partnership agreement, APL distributes to its partners its available cash each quarter. In determining the amount of cash available for distribution, APL sets aside cash reserves, including reserves it believes prudent to maintain for the proper conduct of its business or to provide for future distributions. Additionally, it has relied upon external financing sources, including commercial borrowings and other debt and equity issuances, to fund its acquisition capital expenditures. Accordingly, to the extent APL does not have sufficient cash reserves or is unable to finance growth externally, its cash distribution policy will significantly impair its ability to grow. In addition, to the extent APL issues additional units in connection with any acquisitions or capital expenditures, the payment of distributions on those additional common units may increase the risk that APL will be unable to maintain or increase its per common unit distribution level, which in turn may impact the available cash that AHD has to distribute to us. The incurrence of additional debt to finance its growth strategy would result in increased interest expense to APL, which in turn may impact the available cash that AHD has to distribute to us.

AHD is largely dependent on APL for its growth. As a result of the fiduciary obligations of APL's general partner, which is AHD's wholly-owned subsidiary, to the common unitholders of APL, AHD's ability to pursue business opportunities independently will be limited. AHD currently intends to grow primarily through the growth of APL. While it are not precluded from pursuing business opportunities independently of APL, its subsidiary, as the general partner of APL, has fiduciary duties to APL unitholders which would make it difficult for it to engage in any business activity that is competitive with APL. Those fiduciary duties are applicable to AHD because it controls the general partner through its ability to elect all of its directors. While there may be circumstances in which these fiduciary duties may be satisfied while allowing AHD to pursue business opportunities independent of APL, we expect such opportunities to be limited. Accordingly, AHD may be unable to diversify its sources of revenue in order to increase cash distributions.

APL's common unitholders have the right to remove APL's general partner with the approval of the holders of 66 2/3% of all units, which would cause AHD to lose its general partner interest and incentive distribution rights in APL and the ability to manage APL. AHD currently manages APL through Atlas Pipeline GP, APL's general partner and its wholly-owned subsidiary. APL's partnership agreement, however, gives common unitholders of APL the right to remove the general partner of APL upon the affirmative vote of holders of 66 2/3% of APL's outstanding common units. If Atlas Pipeline GP were removed as general partner of APL, it would receive cash or common units in exchange for its 2.0% general partner interest and the incentive distribution rights and would lose its ability to manage APL. While the common units or cash AHD would receive are intended under the terms of APL's partnership agreement to fully compensate it in the event such an exchange is required, the value of these common units or investments AHD makes with the cash over time may not be equivalent to the value of the general partner interest and the incentive distribution rights had it retained them.

If APL's general partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of APL, its value, and therefore the value of AHD's common units, could decline. The general partner of APL may make expenditures on behalf of APL for which it will seek reimbursement from APL. In addition, under Delaware partnership law, APL's general partner, in its capacity, has unlimited liability for the obligations of APL, such as its debts and environmental liabilities, except for those contractual obligations of APL that are expressly made without recourse to the general partner. To the extent Atlas Pipeline GP incurs obligations on behalf of APL, it is entitled to be reimbursed or indemnified by APL. If APL is unable or unwilling to reimburse or indemnify its general partner, Atlas Pipeline GP may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of AHD's common units.

APL may issue additional limited partner units, which may increase the risk of it not having sufficient available cash to maintain or increase its per unit distribution level. APL has wide discretion to issue additional limited partner units, including units that rank senior to its common units and the incentive distribution rights as to quarterly cash distributions, on the terms and conditions established by its general partner. The payment of distributions on additional APL common units may increase the risk of APL being unable to maintain or increase its per unit distribution level. To the extent new APL limited partner units are senior to the APL common units and the incentive distribution rights, their issuance will increase the uncertainty of the payment of distributions on the common units and the incentive distribution rights. Neither the common units nor the incentive distribution rights are entitled to any arrearages from prior quarters.

AHD may issue an unlimited number of limited partner interests without the consent of its unitholders, which will dilute existing limited partners' ownership interest in its and may increase the risk that AHD will not have sufficient available cash to maintain or increase its per unit distribution level. AHD may issue an unlimited number of limited partner interests of any type without our approval on terms and conditions established by its general partner at any time. The issuance by AHD of additional common units or other equity securities of equal or senior rank will have the following effects:

- AHD's unitholders' proportionate ownership interest in it will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of the common units may decline.

If in the future AHD ceases to manage and control APL through its ownership of its general partner interests, it may be deemed to be an investment company under the Investment Company Act of 1940. If AHD ceases to manage and control APL and is deemed to be an investment company under the Investment Company Act of 1940, it would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify its organizational structure or its contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit its ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from its affiliates, restrict its ability to borrow funds or engage in other transactions involving leverage and require it to add additional directors who are independent of it or its affiliates.

Risks Relating to APL's Business

APL's profitability is affected by the volatility of prices for natural gas and NGL products. APL derives a majority of its revenues from percentage-of-proceeds and keep-whole contracts. As a result, APL's income depends to a significant extent upon the prices at which the natural gas it transports, treats or processes and the natural gas liquids, or NGLs, it produces are sold. A 10% change in the average price of NGLs, natural gas and condensate APL processes and sells would result in a change to our consolidated income for the year ended December 31, 2007, excluding the effect of minority interests in APL's net income, of approximately $5.3 million. Additionally, changes in natural gas prices may indirectly impact APL's profitability since prices can influence drilling activity and well operations and thus the volume of gas APL gathers and processes. 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 APL's control. We expect this volatility to continue. This volatility may cause APL's gross margin and cash flows to vary widely from period to period. APL's 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.

The amount of natural gas APL transports will decline over time unless it is able to attract new wells to connect to its 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 APL's gathering systems could, therefore, result in the amount of natural gas APL transports reducing substantially over time and could, upon exhaustion of the current wells, cause it to abandon one or more of its gathering systems and, possibly, cease operations. The primary factors affecting APL's ability to connect new supplies of natural gas to its gathering systems include APL's success in contracting for existing wells that are not committed to other systems, the level of drilling activity near its gathering systems and, in the Mid-Continent region, APL's ability to attract natural gas producers away from its 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. APL has no control over the level of drilling activity in its service areas, the amount of reserves underlying wells that connect to its systems and the rate at which production from a well will decline. In addition, APL has 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 APL's operating costs are fixed to a significant degree, a reduction in the natural gas volumes it transports or processes would result in a reduction in its gross margin and cash flows.

The success of APL's Appalachian operations depends upon Atlas Energy's ability to drill and complete commercial producing wells. Substantially all of the wells APL connects to its gathering systems in its Appalachian service area are drilled and operated by Atlas Energy for drilling investment partnerships sponsored by it. As a result, APL's 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 APL's 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 APL's Appalachian gathering systems would substantially decrease and could, upon exhaustion of the wells currently connected to APL's gathering systems, cause APL to abandon one or more of its Appalachian gathering systems, thereby materially reducing APL's gross margin and cash flows.

The success of APL's Mid-Continent operations depends upon its ability to continually find and contract for new sources of natural gas supply from unrelated third parties. Unlike APL's Appalachian operations, none of the drillers or operators in its Mid-Continent service area is an affiliate of ours. Moreover, APL's agreements with most of the drillers and operators with which its Mid-Continent operations do business do not require them to dedicate significant amounts of undeveloped acreage to APL's systems. As a result, APL does not have assured sources to provide it with new wells to connect to its Mid Continent gathering systems. Failure to connect new wells to APL's Mid-Continent operations will, as described in "— The amount of natural gas APL transports will decline over time unless it is able to attract new wells to connect to its gathering systems," above, reduce APL's gross margin and cash flows.

APL's 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 its 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 APL's Mid-Continent systems with a majority of their natural gas supply. If these producers reduce the volumes of natural gas that they supply to APL, APL's gross margin and cash flows would be reduced unless it obtains comparable supplies of natural gas from other producers.

The curtailment of operations at, or closure of, any of APL's processing plants could harm its business. APL currently has three processing plants. If operations at any of APL's plants were to be curtailed, or closed, whether due to accident, natural catastrophe, environmental regulation or for any other reason, APL's ability to process natural gas from the relevant gathering system and, as a result, its ability to extract and sell NGLs, would be harmed. If this curtailment or stoppage were to extend for more than a short period, APL's gross margin and cash flows would be materially reduced.

APL may face increased competition in the future in its Mid-Continent service areas. APL's 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 APL's Velma service area. In APL's 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 APL's Ozark Gas Transmission system. CenterPoint and Enogex Inc. operate competing gathering systems in Ozark Gas Gathering's service area. Some of APL's competitors have greater financial and other resources than APL does. If these companies become more active in APL's Mid-Continent service areas, it may not be able to compete successfully with them in securing new well connections or retaining current well connections. If APL does not compete successfully, the amount of natural gas APL transports, processes and treats will decrease, reducing its gross margin and cash flows.

The amount of natural gas APL transports, treats or processes may be reduced if the public utility and interstate pipelines to which APL delivers gas cannot or will not accept the gas. APL's gathering systems principally serve as intermediate transportation facilities between sales lines from wells connected to APL's systems and the public utility or interstate pipelines to which APL delivers natural gas. If one or more of these pipelines has service interruptions, capacity limitations or otherwise does not accept the natural gas APL transports, and APL cannot arrange for delivery to other pipelines, local distribution companies or end users, the amount of natural gas APL transports may be reduced. Since APL's revenues depend upon the volumes of natural gas it transports, this could result in a material reduction in APL's gross margin and cash flows.

Before acquiring its Velma and Elk City operations, APL had no previous experience either in its Mid-Continent service area or in operating natural gas processing plants. APL's Mid-Continent gathering systems are located principally in Oklahoma and northern Texas, areas in which it has 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, APL began to operate natural gas processing plants, a business in which it had no prior operating experience. APL depends upon the experience, knowledge and business relationships that have been developed by the senior management of its Mid-Continent operations to operate successfully in the region. The loss of the services of one or more members of APL's Mid-Continent senior management, in particular, Robert R. Firth, President, and David D. Hall, Chief Financial Officer, could limit its growth or ability to maintain its current level of operations in the Mid-Continent region.

Due to APL's lack of asset diversification, negative developments in its operations would reduce its ability to make distributions to its common unitholders. APL relies exclusively on the revenues generated from its transportation, gathering and processing operations, and as a result, its financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to APL's lack of asset-type diversification, a negative development in one of these businesses would have a significantly greater impact on its financial condition and results of operations than if APL maintained more diverse assets.

APL's construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could impair its results of operations and financial condition. One of the ways APL may grow its business is through the construction of new assets, such as the Sweetwater plant. The construction of additions or modifications to its existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond APL's control and require the expenditure of significant amounts of capital. Any projects APL undertakes may not be completed on schedule at the budgeted cost, or at all. Moreover, APL's revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if APL expands a gathering system, the construction may occur over an extended period of time, and it will not receive any material increases in revenues until the project is completed. Moreover, APL may construct facilities to capture anticipated future growth in production in a region in which growth does not materialize. Since APL is not engaged in the exploration for and development of natural gas reserves, it often does not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent APL relies on estimates of future production in its decision to construct additions to its 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 APL's expected investment return, which could impair its results of operations and financial condition. In addition, APL's 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.

APL recently completed construction of its Sweetwater natural gas processing plant, from which it expects to generate additional incremental cash flow. APL also continues 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 APL.

If APL is unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then it may be unable to fully execute its growth strategy and its cash flows could be reduced. The construction of additions to APL's existing gathering assets may require it to obtain new rights-of-way before constructing new pipelines. APL may be unable to obtain rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for APL 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 its cash flows could be reduced.

Regulation of APL's gathering operations could increase its operating costs, decrease its revenues, or both. Currently APL's 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 APL to regulation by FERC under the Natural Gas Act. APL expects that any such regulation would increase its costs, decrease its gross margin and cash flows, or both.

FERC regulation will still affect APL's business and the market for its products. FERC's policies and practices affect a range of APL's 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 ensure 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 APL's business. Matters subject to regulation include rates, service and safety. APL's 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 APL's right as an owner of gathering facilities to decide with whom it contracts to purchase or transports 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, APL's 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 APL's ability to establish rates that would allow it 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 ensure 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 APL's revenues associated with providing transmission services. We cannot ensure you that APL 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 APL's 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 APL's 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.

Finally, we cannot give any assurance regarding the likely future regulations under which APL will operate Ozark Gas Transmission or the effect such regulation could have on its 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. United States Department of Transportation 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 APL's pipeline will have a material effect on its 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.

There is inherent risk of the incurrence of environmental costs and liabilities in APL's business due to its handling of natural gas and other petroleum products, air emissions related to its operations, historical industry operations including releases of substances into the environment, and waste disposal practices. For example, an accidental release from one of APL's pipelines or processing facilities could subject it 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 APL's compliance costs and the cost of any remediation that may become necessary. APL may not be able to recover some or any of these costs from insurance.

APL may not be able to execute its growth strategy successfully. APL's strategy contemplates substantial growth through both the acquisition of other gathering systems and processing assets and the expansion of its existing gathering systems and processing assets. APL's growth strategy involves numerous risks, including:

- APL may not be able to identify suitable acquisition candidates;
- APL 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;
- APL's costs in seeking to make acquisitions may be material, even if it cannot complete any acquisition it has pursued;
- irrespective of estimates at the time it makes an acquisition, the acquisition may prove to be dilutive to earnings and operating surplus;

- APL may encounter difficulties in integrating operations and systems; and
- any additional debt APL incurs to finance an acquisition may impair its ability to service its existing debt.

Limitations on APL's access to capital or the market for its common units will impair APL's ability to execute its growth strategy. APL's ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, APL has financed its acquisitions, and to a much lesser extent, expansions of its gathering systems by bank credit facilities and the proceeds of public and private equity offerings of its common units and preferred units of its operating partnership. If APL is unable to access the capital markets, it may be unable to execute its strategy of growth through acquisitions.

APL's hedging strategies may fail to protect it and could reduce its gross margin and cash flow. APL pursues various hedging strategies to seek to reduce its exposure to losses from adverse changes in the prices for natural gas and NGLs. APL's hedging activities will vary in scope based upon the level and volatility of natural gas and NGL prices and other changing market conditions. APL's hedging activity may fail to protect or could harm it 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 APL seeks protection;
- the duration of the hedge may not match the duration of the risk against which APL seeks protection; and
- the party owing money in the hedging transaction may default on its obligation to pay.

APL is subject to operating and litigation risks that may not be covered by insurance. APL's 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 APL's pipeline infrastructure, production facilities, transmission and distribution facilities and surrounding properties.

As a result, APL may be a defendant in various legal proceedings and litigation arising from its operations. APL may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. As a result of market conditions, premiums and deductibles for some of APL's 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 APL were to incur a significant liability for which it was not fully insured, its gross margin and cash flows would be materially reduced.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None

ITEM 2: PROPERTIES

Office Properties

Atlas Energy owns a 24,000 square foot office building in Moon Township, Pennsylvania, a 17,000 square foot field office and warehouse facility in Jackson Center, Pennsylvania and an office in Deerfield, Ohio. It leases a 1,400 square foot field office in Ohio under a lease expiring in 2009 and one 4,600 square foot field office in Pennsylvania under a lease expiring in 2009. It also rents 14,100 square feet of office space in Uniontown, Ohio under a lease expiring in August 30, 2008, 2,500 square feet in New York City, NY through July 2008. In addition, Atlas Energy leases other field offices in Ohio and New York on a month-to-month basis. APL leases 37,100 square feet of office space in Tulsa, Oklahoma through November 2009.

Atlas Energy

We owned the properties discussed below until we transferred them on December 18, 2006 to Atlas Energy. Accordingly, we refer to them as Atlas Energy's properties even though we owned them before that date.

Productive Wells

The following table sets forth information as of December 31, 2006 regarding productive natural gas and oil wells in which Atlas Energy has a working interest:

	Number of productive wells	
	Gross [(1)]	Net [(1)]
Oil wells	504	341
Gas wells	6,114	2,927
Total	6,618	3,268

(1) Includes our interest in wells owned by 92 drilling investment partnerships for which Atlas Energy serves as general partner and various joint ventures. Does not include its royalty or overriding interests in 634 wells.

Production

The following table sets forth the quantities of Atlas Energy's natural gas and oil production, average sales prices and average production costs per equivalent unit of production for the periods indicated.

	Production		Average sales price		Average production cost
Period	Oil (bbls)	Gas (mcf)	per bbl	per mcf [(1)]	per mcfe [(2)]
Year ended December 31, 2006	150,628	8,946,376	$ 62.30	$ 8.83	$ 0.86
Three months ended December 31, 2005	39,678	1,975,099	$ 56.13	$ 11.06	$ 0.78
Year ended September 30, 2005	157,904	7,625,695	$ 50.91	$ 7.26	$ 0.71
Year ended September 30, 2004	181,021	7,285,281	$ 32.85	$ 5.84	$ 0.63

(1) Average sales price before the effects of financial hedging was $7.90 for the year ended December 31, 2006. We did not have any financial hedging transactions in any of the other periods presented.

(2) Production costs include labor to operate the wells and related equipment, repairs and maintenance, materials and supplies, property taxes, severance taxes, insurance, gathering charges and production overhead.

Developed and Undeveloped Acreage

The following table sets forth information about Atlas Energy's developed and undeveloped natural gas and oil acreage as of December 31, 2006. The information in this table includes our interest in acreage owned by drilling investment partnerships sponsored by it.

	Developed acreage		Undeveloped acreage	
	Gross	Net	Gross	Net
Arkansas	2,560	403	—	—
Kansas	160	20	—	—
Kentucky	924	462	9,060	4,530
Louisiana	1,819	206	—	—
Mississippi	40	3	—	—
Montana	—	—	2,650	2,650
New York	20,517	15,053	38,172	38,172
North Dakota	639	96	—	—
Ohio	114,226	95,054	37,811	34,287
Oklahoma	4,323	468	—	—
Pennsylvania	107,495	107,495	233,538	233,538
Tennessee	6,400	4,265	4,627	4,627
Texas	4,520	329	—	—
West Virginia	1,078	539	10,806	5,403
Wyoming	—	—	80	80
	264,701	224,393	336,744	323,287

During the fourth quarter of 2006 and the first quarter of 2007, Atlas Energy and its investment partnership drilled three wells to multiple pay zones, including the Marcellus Shale of Southwest Pennsylvania. The Marcellus Shale is a black, organic rich shale formation located at depths between 7,000 and 8,500 feet and ranges in thickness from 100 to 150 feet on our acreage in Fayette, Westmoreland and Greene Counties. Atlas Energy currently holds approximately 157,500 acres of prospective Marcellus acreage in these counties. Most of this acreage is held by production, meaning that it is covered by a continuing lease due to production from the property.

The leases for Atlas Energy's developed acreage generally have terms that extend for the life of the wells, while the leases on its undeveloped acreage have terms that vary from less than one year to five years. Atlas Energy paid rentals of approximately $885,000 in the year ended December 31, 2006 to maintain the leases.

We believe that Atlas Energy holds good and indefeasible title to its producing properties, in accordance with standards generally accepted in the natural gas industry, subject to exceptions stated in the opinions of counsel employed by it in the various areas in which Atlas Energy conducts its activities. We do not believe that these exceptions detract substantially from the use of any property. As is customary in the natural gas industry, Atlas Energy conducts only a perfunctory title examination at the time it acquires a property. Before it commences drilling operations, it conducts an extensive title examination and performs curative work on defects that it deems significant. Atlas Energy has obtained title examinations for substantially all of its managed producing properties. No single property represents a material portion of its holdings.

Atlas Energy's properties are subject to royalty, overriding royalty and other outstanding interests customary in the industry. Atlas Energy's properties are also subject to burdens such as liens incident to operating agreements, taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. We do not believe that any of these burdens will materially interfere with the use of its properties.

Drilling Activity

The following table sets forth information with respect to the number of wells in which Atlas Energy completed drilling during the periods indicated, regardless of when drilling was initiated.

	Development wells				Exploratory wells			
	Productive		Dry		Productive		Dry	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Year ended December 31, 2006	711.0	235.3	4.0	1.4	—	—	—	—
Three months ended December 31, 2005	192.0	64.1	—	—	—	—	—	—
Year ended September 30, 2005	644.0	210.0	18.0	6.3	—	—	—	—
Year ended September 30, 2004	493.0	160.5	11.0	3.8	—	—	1.0	1.0

(1) Includes the number of physical wells in which Atlas Energy holds any working interest, regardless of its percentage interest.

(2) Includes (i) Atlas Energy's percentage interest in wells in which it has a direct ownership interest and (ii) with respect to wells in which it has an indirect ownership interest through its investment partnerships, its percentage interest in the wells based on its percentage interest in its investment partnerships and not those of the other partners in its investment partnerships.

Natural Gas and Oil Reserves

The following tables summarize information regarding Atlas Energy's estimated proved natural gas and oil reserves as of the dates indicated. All of Atlas Energy's reserves are located in the United States. Atlas Energy bases its estimates relating to its proved natural gas and oil reserves and future net revenues of natural gas and oil reserves upon reports prepared by Wright & Company, Inc, energy consultants. In accordance with SEC guidelines, Atlas Energy makes the standardized and PV-10 estimates of future net cash flows from proved reserves using natural gas and oil sales prices in effect as of the dates of the estimates which are held constant throughout the life of the properties. Atlas Energy based its estimates of proved reserves upon the following weighted average prices:

	At December 31,		At September 30,	
	2006	2005	2005	2004
Natural gas (per Mcf)	$ 6.33	$ 10.84	$ 14.75	$ 6.91
Oil (per Bbl)	$ 57.26	$ 57.54	$ 63.29	$ 46.00

Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas and oil reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve reports of other engineers might differ from the reports of our consultants, Wright & Company. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of this estimate. Future prices received from the sale of natural gas and oil may be different from those estimated by Wright & Company in preparing its reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, the reserves set forth in the following tables ultimately may not be produced and the proved undeveloped reserves may not be developed within the periods anticipated. You should not construe the estimated PV-10 values as representative of the fair market value of Atlas Energy's proved natural gas and oil properties. PV-10 values are based upon projected cash inflows, which do not provide for changes in natural gas and oil prices or for the escalation of expenses and capital costs. The meaningfulness of these estimates depends upon the accuracy of the assumptions upon which they were based.

Atlas Energy evaluates natural gas reserves at constant temperature and pressure. A change in either of these factors can affect the measurement of natural gas reserves. Atlas Energy deducts operating costs, development costs and production-related and ad valorem taxes in arriving at the estimated future cash flows. Atlas Energy bases the estimates on operating methods and conditions prevailing as of the dates indicated. Atlas Energy cannot assure you that these estimates are accurate predictions of future net cash flows from natural gas and oil reserves or their present value. For additional information concerning Atlas Energy's natural gas and oil reserves and estimates of future net revenues, see Note 16 of our Notes to Consolidated Financial Statements.

	Proved natural gas and oil reserves			
	December 31,		September 30,	
	2006	2005	2005	2004
Natural gas reserves (mmcf):				
Proved developed reserves	107,683	108,674	104,786	95,788
Proved undeveloped reserves	60,859	49,250	53,241	46,345
Total proved reserves of natural gas	168,542	157,924	158,027	142,133
Oil reserves (mbbl):				
Proved developed reserves	2,064	2,122	2,116	2,126
Proved undeveloped reserves	4	135	143	149
Total proved reserves of oil	2,068	2,257	2,259	2,275
Total proved reserves (mmcfe)	180,950	171,466	171,581	155,782
Standardized measure of discounted future cash flows (in thousands)	$ 205,520	$ 429,272	$ 606,697	$ 232,998
PV-10 estimate of cash flows of proved reserves (in thousands):				
Proved developed reserves	$ 276,138	$ 465,459	$ 617,445	$ 265,516
Proved undeveloped reserves	4,111	131,678	228,206	54,863
Total PV-10 estimate	$ 280,249	$ 597,137	$ 845,651	$ 320,379

Projected natural gas and oil volumes for each of calendar 2007 and the remaining successive years are:

	Calendar 2007	Remaining successive years	Total
Natural gas (mmcf)	10,329	158,213	168,542
Oil (mbbl)	141	1,927	2,068

Atlas Pipeline

As of December 31, 2006, AHD's assets consisted of its ownership interests in APL. As of December 31, 2006, APL's principal facilities in Appalachia include approximately 1,600 miles of 2 to 12 inch diameter pipeline. APL's 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 APL's gathering systems and its 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 APL's compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

APL's property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not interfered, and we do not expect that they will materially interfere, with the conduct of APL's 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, APL's 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 APL's 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.

ITEM 3: LEGAL PROCEEDINGS

One of Atlas Energy's subsidiaries, Resource Energy, LLC, together with Resource America, is a defendant in a class action originally filed in February 2000 in the New York Supreme Court, Chautauqua County, by individuals, putatively on their own behalf and on behalf of similarly situated individuals, who leased property to us. The complaint alleges that we are not paying landowners the proper amount of royalty revenues with respect to natural gas produced from the leased properties. The complaint seeks damages in an unspecified amount for the alleged difference between the amount of royalties actually paid and the amount of royalties that allegedly should have been paid. In October 2006 we reached a tentative settlement of this lawsuit, the settlement terms are subject to final approval by the court. Pursuant to the tentative settlement terms, we have agreed to pay $300,000, upgrade certain gathering systems and cap certain transportation expenses chargeable to the land owners.

We are also a party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of results of operations.

ITEM 4: SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed for trading on The NASDAQ Stock Market under the symbol "ATLS." The following table sets forth, for the fiscal quarters indicated, the high and low sales prices per share as reported on The NASDAQ Stock Market. The quarterly share prices have been adjusted to reflect the 3-for-2 stock split on March 10, 2006. In 2006, we changed our fiscal year end from September 30 to December 31.

	High	Low
Fiscal year ended September 30, 2005		
First quarter	$ 24.27	$ 14.35
Second quarter	27.45	21.71
Third quarter	25.79	20.13
Fourth quarter	33.93	25.47
Quarter ended December 31, 2005	42.42	28.25
Fiscal year ended December 31, 2006		
First quarter	49.15	41.35
Second quarter	53.14	40.11
Third quarter	47.73	41.50
Fourth quarter	52.02	40.27

Since May 11, 2004, the date of our initial public offering, we have not paid any cash dividends on our common stock. As of February 22, 2007, there were 19,353,609 shares of common stock outstanding held by 291 holders of record.

On February 6, 2006, our Board of Directors approved a three-for-two stock split effected in the form of a 50% stock dividend. Shareholders of record as of February 28, 2006, received one additional share of common stock for each two shares of common stock they owned on that date. The shares were distributed on March 10, 2006, and the adjusted per share stock price was reported by the NASDAQ Stock Market, effective March 13, 2006.

For information concerning common stock authorized for issuance under our stock incentive plan, see Note 9 of our Notes to Consolidated Financial Statements.

ITEM 6. SELECTED FINANCIAL DATA

In June 2006, we changed our year end to December 31 from September 30 and therefore information below includes our transition period, the three months ended December 31, 2005, and our new year ended December 31, 2006.

The following table sets forth selected financial data as of and for the years ended September 30, 2002 through 2005, the three months ended December 21, 2005 and the year ended December 31, 2006. We derived the financial data as of December 31, 2006 and 2005, September 30, 2005 and 2004 and for the year ended December 31, 2006, three months ended December 31, 2005 and years ended September 30, 2005, 2004 and 2003 from our financial statements, which were audited by Grant Thornton LLP, independent accountants, and are included in this report. We derived the financial data as of September 30, 2003 and 2002 and for the years ended September 30, 2003 and 2002 from our financial statements, which were audited by Grant Thornton LLP, and are not included in this report.

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004	2003	2002
	(in thousands, except per share data)					
Income statement data:						
Revenues	$ 749,306	$ 200,496	$ 481,980	$ 186,460	$ 110,143	$ 93,263
Income from continuing operations before cumulative effect of accounting change	12,176	11,724	32,940	21,187	13,720	8,882
Basic net income per share from continuing operations before cumulative effect of accounting change	$ .62	$ 0.59	$ 1.65	$ 1.18	$ 0.85	$ 0.55
Diluted net income per share from continuing operations before cumulative effect of accounting change	$ .60	$ 0.58	$ 1.64	$ 1.18	$ 0.85	$ 0.55

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004	2003	2002
	(in thousands)					
Other financial information:						
Net cash provided by operating activities	$ 42,324	$ 52,769	$ 112,045	$ 50,043	$ 44,941	$ 1,829
Capital expenditures	$ 159,466	$ 31,809	$ 99,185	$ 41,162	$ 28,029	$ 21,291
EBITDA [1]	$ 142.286	$ 35,081	$ 89,320	$ 50,177	$ 34,033	$ 26,601
Balance sheet data:						
Total assets	$ 1,376,926	$ 1,056,180	$ 759,711	$ 423,709	$ 232,388	$ 192,614
Long-term debt	$ 324,151	$ 298,781	$ 191,727	$ 85,640	$ 31,194	$ 49,505
Stockholders' equity	$ 132,662	$ 132,850	$ 120,351	$ 91,003	$ 87,511	$ 73,366

(1) We define EBITDA as earnings before interest, taxes, depreciation, depletion and amortization. EBITDA is not a measure of performance calculated in accordance with accounting principles generally accepted in the United States, or GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies and is different from the EBITDA calculation under our various credit facilities. See "Credit Facilities." In addition, EBITDA does not represent funds available for discretionary use. The following reconciles EBITDA to our income from continuing operations for the periods indicated.

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004	2003	2002
			(in thousands)			
Income from continuing operations cumulative effect of accounting change	$ 12,176	$ 11,724	$ 32,940	$ 21,187	$ 13,720	$ 8,882
Plus interest expense	27,313	6,147	11,467	2,881	1,961	2,200
Plus income taxes	57,154	6,886	20,018	11,409	6,757	4,683
Plus depreciation, depletion and amortization	45,643	10,324	24,895	14,700	11,595	10,836
EBITDA	$ 142,286	$ 35,081	$ 89,320	$ 50,177	$ 34,033	$ 26,601

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

Overview of Years Ended December 31, 2006 and 2005, Three Months Ended December 31, 2005 and 2004 and Years Ended September 30, 2005 and 2004

Change in Year End

On June 15, 2006, our Board of Directors changed our year end from September 30 to December 31. The financial results now being reported by us relate to the year ended December 31, 2006, and the three-month transitional period ended December 31, 2005. In order to compare the financial information for the year ended December 31, 2006 in Management's Discussion and Analysis of Financial Condition and Results of Operations to a like period, we prepared financial information for the twelve months ended December 31, 2005, which includes the three-month transitional period ended December 31, 2005, and the nine months ended September 30, 2005. Wherever practicable, the forthcoming discussion will compare the consolidated financial statements for calendar year 2006 with the recast pro forma financial statements for the twelve months ended December 31, 2005. For purposes of Management's Discussion and Analysis of Financial Condition and Results of Operations, we believe that this comparison provides a more meaningful analysis.

Throughout this discussion, data for all periods except for the twelve months ended December 31, 2005 and three months ended December 31, 2004, are derived from our consolidated financial statements, which appear in this report.

Spin-off by Resource America

On June 30, 2005, RAI distributed the remaining 10.7 million shares it owned in us to its stockholders in the form of a tax-free dividend. Each stockholder of RAI received 0.59367 of a share of our common stock for each share of RAI common stock owned on June 24, 2005, the record date. Although the distribution itself was tax-free to RAI's stockholders, as a result of the deconsolidation there may be some tax liability arising from prior unrelated corporate transactions among us and some of our subsidiaries. We anticipate that all or a portion of any liability arising from this transaction may be paid by us to RAI. In addition, we were required to make a non-recurring income tax payment, payable to Resource America, of $1.2 million associated with the spin-off.

Restructuring

In December 2006, we contributed substantially all of our natural gas and oil assets and our investment partnership management business to Atlas Energy, a then wholly-owned subsidiary. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a 19.5% ownership interest, in an initial public offering at a price of $21.00 per unit. The net proceeds of approximately $139.9 million after underwriting discounts and commissions were distributed to us. After completion of the offering, we have an approximate 78.5% ownership interest in Atlas Energy. Additionally, we own Atlas Energy Management, which owns 2% of the membership interests and all of the management incentive interests in Atlas Energy.

In July 2006, we contributed our ownership interests in Atlas Pipeline GP, our then wholly-owned subsidiary, and the general partner of Atlas Pipeline Partners to AHD. Concurrent with this transaction, AHD issued 3,600,000 common units representing a 17.1% ownership interest in it, in an initial public offering at a price of $23.00 per unit. The net proceeds of approximately $74.3 million after underwriting discounts and commissions were distributed to us.

Corporate Profile

As a result of this restructuring, we have condensed our $1.4 billion in assets into two primary energy business operations: exploration and development and natural gas gathering and processing.

Exploration and Development – Atlas Energy

Atlas Energy is a limited liability company focused on the development and production of natural gas and, to a lesser extent, oil principally in the Appalachian Basin. Atlas Energy sponsors and manages tax-advantaged investment partnerships, in which it coinvests, to finance the exploitation and development of its acreage. Atlas Energy raised $218.5 million through its investment partnerships in 2006 which represented a 47% increase over the $148.7 million raised in 2005 which was a 38% increase over the $107.7 million raised in 2004.

Atlas Energy's gross revenues depend, to a significant extent, on the price of natural gas and oil which can fluctuate significantly. It seeks to balance this volatility with the more stable net income from its well drilling and well servicing operations which are principally fee-based. Atlas Energy's business strategy for increasing its reserve base includes acquisitions of undeveloped properties or companies with significant amounts of undeveloped property. At December 31, 2006, Atlas Energy had $154.5 million available under its credit facility, which could be employed to finance such acquisitions.

Transmission, Gathering and Processing – AHD

AHD's primary subsidiary, Atlas Pipeline GP, is the general partner of Atlas Pipeline, which is a mid-stream service provider engaged in the transmission, gathering and processing of natural gas. Atlas Pipeline is 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, Atlas Pipeline is a leading provider of natural gas processing services in Oklahoma and also provides interstate gas transmission services in southeastern Oklahoma, Arkansas and southeastern Missouri. Atlas Pipeline conducts its business through two operating segments: its Mid-Continent operations and its Appalachian operations.

Atlas Pipeline's financial condition and results of operations have been significantly affected by acquisitions and capital market activities.

Acquisitions. From the date of its initial public offering in January 2000 through December 2006, Atlas Pipeline has completed six acquisitions at an aggregate cost of approximately $590.1 million, including most recently:

NOARK – acquired a 100% ownership interest, in two separate transactions, in NOARK for a net purchase price of $228.5 million, including 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.

Elk City – acquired for $196.0 million, including transaction costs. Elk City's principal assets include approximately 450 miles of natural gas pipelines, a natural gas processing facility and a gas treatment facility located in the Anadarko Basin in western Oklahoma and the Texas panhandle.

Spectrum – acquired for $141.6 million, including transaction costs and payment of taxes due as a result of the transaction. Velma's principal assets include 1,900 miles of natural gas pipelines and a natural gas processing facility located in the Golden Trend area of southern Oklahoma and the Barnett Shale area of North Texas.

Capital Market Activities. Atlas Pipeline has managed its capital structure to finance its acquisitions, organic growth projects, and working capital needs through the following activities:

Common Unit Equity Offerings – From January 2004 through December 31, 2006, Atlas Pipeline has sold 8.7 million common limited partner units for net proceeds of $325.5 million, after underwriting commissions and other transaction costs.

Senior Notes Offerings – In two separate transactions during December 2005 and May 2006, Atlas Pipeline issued $285.0 million principal amount of 10-year senior unsecured notes at a weighted average effective yield of approximately 8.1% for net proceeds of $279.9 million, after initial purchaser's discount and other transaction costs.

Preferred Unit Equity Offerings – During 2006, Atlas Pipeline sold 40,000 6.5% cumulative convertible preferred limited partner units for net proceeds of $39.9 million, after underwriting commissions and other transaction costs.

Revolving Credit Facility – Atlas Pipeline has a $225.0 million credit facility which matures in June 2011.

Mid-Continent Operations. As a result of the Mid-Continent acquisitions, Atlas Pipeline's Mid-Continent operations consist of:

- 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 its natural gas processing plants or transmission lines.

Appalachian Operations. Through its Appalachian operations, Atlas Pipeline owns and operates 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 Atlas Pipeline and Atlas America and its affiliates, including Atlas Energy Resources, LLC and subsidiaries, Atlas Pipeline gathers substantially all of the natural gas for its Appalachian Basin operations from wells operated by Atlas Energy.

Exploration and Development – Atlas Energy

Gas and Oil Production

The following table sets forth information relating to our consolidated production revenues, production volumes, sales prices, production costs and depletion for our operations during the periods indicated:

	Years Ended December 31,		Three Months Ended December 31,		Years Ended September 30,	
	2006	2005	2005	2004	2005	2004
Production revenues (in thousands):						
Gas (1)	$ 79,016	$ 64,530	$ 21,851	$ 12,697	$ 55,376	$ 42,532
Oil	$ 9,384	$ 8,324	$ 2,227	$ 1,942	$ 8,039	$ 5,947
Production volumes:						
Gas (Mcf/d) (1) (2)	24,511	21,190	21,468	20,286	20,892	19,905
Oil (Bbls/d)	413	429	431	447	433	495
Total (Mcfe/d)	26,989	23,764	24,054	22,968	23,490	22,875
Average sales prices:						
Gas (per Mcf) (3)	$ 8.83	$ 8.34	$ 11.06	$ 6.80	$ 7.26	$ 5.84
Oil (per Bbl)	$ 62.30	$ 53.22	$ 56.13	$ 47.17	$ 50.91	$ 32.85
Production costs (4):						
As a percent of production revenues	10%	9%	7%	8%	10%	11%
Per Mcfe	$ 0.86	$ 0.76	$ 0.78	$ 0.83	$ 0.71	$ 0.63
Depletion per Mcfe	$ 2.08	$ 1.61	$ 2.01	$ 1.28	$ 1.42	$ 1.22

(1) Excludes sales of residual gas and sales to landowners.

(2) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the investment partnerships in which we have an interest, based on our equity interest in each such partnership and based on each partnership's proportionate net revenue interest in these wells.

(3) Our average sales price before the effects of financial hedging was $7.90 per mcf for the year ended December 31 2006. We had no financial hedging transactions in any of the other periods presented

(4) Production costs include labor to operate the wells and related equipment, repairs and maintenance, materials and supplies, property taxes, severance taxes, insurance and production overhead.

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

Our natural gas revenues were $79.0 million for the year ended December 31, 2006, an increase of $14.5 million (22%) from $64.5 million for the year ended December 31, 2005. The increase was due to a 6% increase in the average sales price of natural gas and a 16% increase in production volumes. The $14.5 million increase in natural gas revenues consisted of $3.8 million attributable to price increases and $10.7 million attributable to volume increases.

Our oil revenues were $9.4 million for the year ended December 31, 2006, an increase of $1.1 million (13 %) from $8.3 million for the year ended December 31, 2005. The increase resulted from a 17% increase in the average sales price of oil, partially offset by a 4% decrease in production volumes. The $1.1 million increase in oil revenues consisted of $1.5 million attributable to price increases, partially offset by $0.4 million attributable to volume decreases, as we drill primarily for natural gas rather than oil.

Our production costs were $8.5 million for the year ended December 31, 2006, an increase of $1.9 million (29%) from $6.6 million for the year ended December 31, 2005. This increase includes normal operating expenses and coincides with the increased production volumes we realized from the increased number of wells we operate.

Three Months Ended December 31, 2005 Compared to December 31, 2004

Our natural gas revenues were $21.9 million in the three months ended December 31, 2005, an increase of $9.2 million (72%) from $12.7 million in the three months ended December 31, 2004. The increase in the three months ended December 31, 2005 was attributable to an increase in the average sales price of natural gas of 63% for the three months ended December 31, 2005 and an increase of 6% in the volume of natural gas produced in the three months ended December 31, 2005. The $9.2 million increase in gas revenues in the three months ended December 31, 2005 as compared to the prior period consisted of $8.0 million attributable to increases in natural gas sales prices, and $1.2 attributable to increased production volumes.

Our oil revenues were $2.2 million in the three months ended December 31, 2005, an increase of $285,000 (15%), from $1.9 million in the three months ended December 31, 2004, primarily due to an increase in the average sales price of oil of 19% for the three months ended December 31, 2005. The $285,000 increase in oil revenues in three months ended December 31, 2005 as compared to the prior period consisted of $369,000 attributable to increases in sales prices, partially offset by a decrease of $84,000 attributable to decreased production volumes.

Our production costs were $1.7 million in the three months ended December 31, 2005, an increase of $524,000 (44%) from $1.2 million in the three months ended December 31, 2004. This increase includes an increase in labor costs related to well pumping operations as a result of an increase in the number of wells we operate. Production costs as a percent of production revenues decreased in the three months ended December 31, 2005 as compared to December 31, 2004 as a result of an increase in our average sales price which more than offset the increase in production costs per mcfe.

Year Ended September 30, 2005 Compared to Year Ended September 30, 2004

Our natural gas revenues were $55.4 million in fiscal 2005, an increase of $12.9 million (30%) from $42.5 million in fiscal 2004. The increase was due to a 24% increase in the average sales price of natural gas and a 5% increase in production volumes. The $12.9 million increase in natural gas revenues consisted of $10.4 million attributable to price increases and $2.5 million attributable to volume increases.

Our oil revenues were $8.0 million in fiscal 2005, an increase of $2.1 million (35%) from $5.9 million in fiscal 2004. The increase resulted from a 55% increase in the average sales price of oil, partially offset by a 13% decrease in production volumes. The $2.1 million increase in oil revenues consisted of $3.3 million attributable to price increases, partially offset by $1.2 million attributable to volume decreases, as we drill primarily for natural gas rather than oil.

Our production costs were $8.2 million in fiscal 2005, an increase of $900,000 (12%) from $7.3 million in fiscal 2004. This increase includes normal operating expenses and coincides with the increased production volumes we realized from the increased number of wells we operate.

Well Construction and Completion

Our well drilling revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for drilling investment partnerships we sponsor. The following table sets forth information relating to these revenues and the related costs, gross profit margins and number of net wells drilled during the periods indicated (in thousands):

	Years Ended December 31,		Three Months Ended December 31,		Years Ended September 30,	
	2006	2005	2005	2004	2005	2004
Average construction and completion revenue per well	$ 307	$ 219	$ 225	$ 224	$ 218	$ 193
Average construction and completion cost per well	267	191	196	195	190	168
Average construction and completion segment margin per well	$ 40	$ 28	$ 29	$ 29	$ 28	$ 25
Segment margin	$ 25,901	$ 19,034	$ 5,497	$ 3,985	$ 17,552	$ 11,332
Net wells drilled	647	666	187	136	615	450

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

Our well construction and completion segment margin was $25.9 million in the year ended December 31, 2006, an increase of $6.9 million (36%) from $19.0 million in the year ended December 31, 2005. During the year ended December 31, 2006, the increase of $6.9 million was attributable to an increase in the gross profit per well ($7.7 million) partially offset by a decrease in the number of wells drilled ($759,000). Since our drilling contracts are on a “cost plus” basis (typically cost plus 15%), an increase in our average cost per well also results in an increase in our average revenue per well. The increase in our average cost per well in the year ended December 31, 2006 resulted from an increase in the cost of tangible equipment, leases, site preparation and reclamation expenses, as well as increased costs due to drilling into deeper formations.

It should be noted that “Liabilities associated with drilling contracts” on our balance sheet includes $71.6 million of funds raised in our investment programs that have not been applied to the completion of wells as of December 31, 2006 due to the timing of drilling operations, and thus have not been recognized as well construction and completion revenue. We expect to recognize this amount as revenue by March 31, 2007. During the year ended December 31, 2006, we raised $218.5 million. We anticipate raising $270.0 million in 2007. We anticipate oil and gas prices will continue to favorably impact our fundraising and therefore our drilling revenues in the year ending December 31, 2007.

Three months ended December 31, 2005 compared to three months ended December 31, 2004

Our well construction and completion segment margin was $5.5 million in the three months ended December 31, 2005, an increase of $1.5 million (38%) from $4.0 million in the three months ended December 31, 2004. During the three months ended December 31, 2005, the increase of $1.5 million was attributable to an increase in the number of wells drilled. Since our drilling contracts are on a “cost plus” basis (typically cost plus 15%), an increase in our average cost per well also results in an increase in our average revenue per well.

It should be noted that “Liabilities associated with drilling contracts” on our balance sheet includes $59.0 million of funds raised in our investment programs that have not been applied to the completion of wells as of December 31, 2005 due to the timing of drilling operations, and thus have not been recognized as well construction and completion revenue.

Year Ended September 30, 2005 Compared to Year Ended September 30, 2004

Our well drilling gross margin was $17.5 million in the year ended September 30, 2005, an increase of $6.2 million (55%) from $11.3 million in the year ended September 30, 2004. During the year ended September 30, 2005, the increase in gross margin was attributable to an increase in the number of wells drilled ($4.7 million) and an increase in the gross profit per well ($1.5 million). Since our drilling contracts are on a “cost plus” basis (typically cost plus 15%), an increase in our average cost per well also results in an increase in our average revenue per well. The increase in our average cost per well resulted from an increase in the cost of tangible equipment, leases, site preparation and reclamation expenses, as well as increased costs due to drilling into deeper formations.

It should be noted that “Liabilities associated with drilling contracts” on our balance sheet as of September 30, 2005 included $49.9 million of funds raised in our drilling investment partnerships in fiscal 2005 that had not been applied to drill wells as of September 30, 2005 due to the timing of drilling operations, and thus had not been recognized as well drilling revenues. We completed our fundraising for calendar year 2005 in November 2005 with a total of $55.0 million raised after our fiscal year end, bringing the total for the calendar year to $116.6 million.

Transmission, Gathering and Processing – AHD

The following table illustrates selected volumetric information related to Atlas Pipeline's operating segments for the periods indicated:

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004
Operating data:				
Appalachia:				
Average throughput volume (Mcfd)	61,892	56,391	54,885	52,078
Mid-Continent:				
Velma system:				
Gathered gas volume (Mcfd)	60,682	61,093	66,099	55,580
Elk City/Sweetwater system:				
Gathered gas volume (Mcfd)	277,063	266,280	242,294	—
NOARK system:				
Average Ozark Gas Transmission throughput volume (Mcfd)	249,581	255,777	—	—
Combined throughput volume (Mcfd)	649,218	639,541	363,278	107,658

Transmission, gathering, and processing below includes revenues earned by Atlas Pipeline's Appalachian segment under its master gas gathering agreement with us or Atlas Energy which is eliminated upon consolidation in our financial statements. Revenues earned under this agreement were approximately $30.3 million, $7.9 million, $21.9 million and $17.2 million the year ended December 31, 2006, three months ended December 31, 2005, and year ended September 30, 2005 and 2004. This is offset by transportation revenues received by us from our investment partnerships for gathering services of $9.3 million, $1.4 million, $4.3 million and $4.2 million for the same periods.

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

Our transmission, gathering and processing revenues were $458.6 million for the year ended December 31, 2006, an increase of $113.0 million (23.9%) from $370.2 million for the year ended December 31, 2005. The increase was attributable to revenue contributions from Atlas Pipeline's NOARK and Elk City systems, which were acquired during 2005 and 2006, partially offset by a decrease from Atlas Pipeline's Velma system due principally to a decrease in natural gas prices and lower processed volumes. Gathered natural gas volume averaged 60.7 MMcfd on Atlas Pipeline's Velma system for the year ended December 31, 2006, a decrease of 10% 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. Gathered natural gas volume on the Elk City system averaged 277.1 MMcfd for the year ended December 31, 2006, an 11% increase from the prior year. For the NOARK system, average Ozark Gas Transmission throughput volume was 249.6 MMcfd for the year ended December 31, 2006.

Our transmission, gathering and processing costs and expenses were $360.9 million for the year ended December 31, 2006, an increase of $56.9 million (18.7%) from $304.0 million for the year ended December 31, 2005. The increase was primarily related to costs associated with the revenue contributions from Atlas Pipeline's NOARK and Elk City acquisitions and higher Appalachia system operating costs as a result of compressors added during 2005 in connection with a capacity expansion project and higher maintenance expense associated with additional wells connected to the gathering system. These amounts were partially offset by a decrease from Atlas Pipeline's Velma system due to a decline in natural gas prices and lower volume.

Three Months Ended December 31, 2005 Compared to Three Months Ended December 31, 2004

Our transmission, gathering and processing revenues were $135.3 million for the three months ended December 31, 2005, an increase of $87.9 million from $47.4 million for the three months ended December 31, 2004. The increase was primarily attributable to revenue contributions from Atlas Pipeline's Elk City system, which was acquired during April 2005. Gathered natural gas volume averaged 67.1 MMcfd on Atlas Pipeline's Velma system for the three months ended December 31, 2005, an increase of 19% from the prior year quarter. Gathered natural gas volume on the Appalachia system averaged 55.2 MMcfd for the three months ended December 31, 2005, a 3% increase from the prior year quarter.

Our transmission, gathering and processing costs and expenses were $109.9 million for the three months ended December 31, 2005, an increase of $74.2 million from $35.7 million for the three months ended December 31, 2005. The increase was primarily related to costs associated with the revenue contributions from Atlas Pipeline's Elk City acquisition.

Year Ended September 30, 2005 Compared to Year Ended September 30, 2004

Our transmission, gathering and processing revenues were $282.3 million for the year ended September 30, 2005, an increase of $235.1 million from $47.2 million for the year ended September 30, 2004. The increase was attributable to revenue contributions from Atlas Pipeline's Elk City system, which was acquired during April 2005, and its Velma system, which was acquired in July 2004, and higher commodity prices. Gathered natural gas volume averaged 65.9 MMcfd on Atlas Pipeline's Velma system for the year ended September 30, 2005, an increase of 58% from the prior period from its date of acquisition through September 30, 2004. Gathered natural gas volume on the Elk City system averaged 181.2 MMcfd from its date of acquisition through September 30, 2005.

Our transmission, gathering and processing costs and expenses were $229.8 million for the year ended September 30, 2005, an increase of $202.0 million from $27.8 million for the year ended September 30, 2004. The increase was primarily related to costs associated with the revenue contributions from Atlas Pipeline's Elk City and Velma acquisitions, an increase in commodity prices and higher Appalachia system operating costs as a result of compressors added during 2005 in connection with a capacity expansion project and higher maintenance expense associated with additional wells connected to the gathering system.

Other Income, Costs and Expenses

General and Administrative

Year Ended December 31, 2006

Our general and administrative expenses were $46.5 million in the year ended December 31, 2006 consisted principally of the following:

- costs associated with running our corporate offices and partnership syndication activities of $7.6 million;
- salaries, wages and benefits of $26.7 million of which $15.4 million related to Atlas Pipeline and $11.3 million related to Atlas Energy;
- professional fees and insurance of $6.7 million, which includes the implementation of Sarbanes-Oxley Section 404 compliance, costs of our audit and tax preparation and the evaluation of our oil and gas reserves; and
- exploration costs of $3.0 million.

Three Months Ended December 31, 2005

Our general and administrative expenses in the three months ended December 31, 2005 were $9.5 million and consisted principally of the following:

- $4.8 million in salary, wages and benefits;
- $2.4 million in professional fees and insurance; and
- $1.3 million in corporate overhead and syndication activities.

Year Ended September 30, 2005 Compared to Year Ended September 30, 2004

Our general and administrative expenses were $24.0 million in fiscal 2005, an increase of $9.0 million (60%) from $15.0 million in fiscal 2004. These increases are principally attributable to the following:

- general and administrative expenses related to Atlas Pipeline's Mid-Continent operations were $3.8 million, an increase of $3.3 million primarily attributable to costs associated with operations of Elk City acquired in April 2005, and a full year of expense associated with operations of Mid-Continent, acquired in July 2004;
- costs associated with Atlas Pipeline's long term incentive plan were $3.2 million, an increase of $2.9 million over fiscal 2004;
- salaries and wages increased $3.0 million due to an increase in executive salaries and an increase in the number of employees as a result of our spin-off from our parent;
- professional fees and insurance increased $1.7 million, which includes the implementation of Sarbanes-Oxley Section 404 compliance, and

These increases were partially offset by $1.9 million of increased credits received for organizing and offering costs incurred in syndicating our partnerships as we continue to increase the amount of money raised.

Depletion

We are subject to variances in our depletion rates from period to period, including the periods described below. These variances result from changes in our oil and gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and gas properties.

Year ended December 31, 2006 compared to Year ended December 31, 2005

Our depletion of oil and gas properties as a percentage of oil and gas revenues was 23% in the year ended December 31, 2006 compared to 19% in 2005. Depletion was $2.08 per mcfe in the year ended December 31, 2006, an increase of $.47 per mcfe (29%) from $1.61 per mcfe in 2005. Increases in our depletable basis and production volumes caused depletion expense to increase $6.6 million to $20.5 million in 2006 compared to $13.9 million in 2005.

Three months ended December 31, 2005 compared to the three months ended December 31, 2005

Our depletion of oil and gas properties as a percentage of oil and gas revenues was 18% in the three months ended December 31, 2005 and December 31, 2004. Depletion expense per mcfe was $2.01 in the three months ended December 31, 2005, an increase of $.73 (57%) per mcfe from $1.28 in the three months ended December 31, 2004. Depletion expense increased $1.7 million (65%) to $4.4 million in the three months ended December 31, 2005 compared to $2.7 million in the three months ended December 31, 2004.

Year ended September 30, 2005 compared to year ended September 30, 2004

Depletion of oil and gas properties as a percentage of oil and gas revenues was 19% in 2005 compared to 21% in 2004. Depletion was $1.42 per mcfe in 2005, an increase of $.20 per mcfe (16%) from $1.22 per mcfe in 2004. Depletion expense increased $2.0 million to $12.2 million in 2005 compared to $10.2 million in 2004.

Depreciation and Amortization

Depreciation and amortization expense was $25.2 million, $ 5.9 million, $ 12.7 and $ 4.5 in the year ended December 31, 2006, three months ended December 31, 2005, and in the years ended September 30, 2005 and 2004. These increases are due to the increase in property and equipment base associated with Atlas Pipeline's Mid-Continent acquisitions.

Interest Expense

Year Ended December 31, 2006 compared to Year ended December 31, 2005

Our interest expense was $27.3 million in the year ended December 31, 2006, an increase of $11.4 million from $15.9 million in the year ended December 31, 2005. This increase resulted primarily from an increase in outstanding borrowings by Atlas Pipeline as well as $1.2 million of accelerated amortization of deferred financing costs associated with the retirement of our credit facility in association with the formation Atlas Energy and its new credit facility in December 2006.

Year ended September 30, 2005 compared to year ended September 30, 2005

Our interest expense was $11.5 million in fiscal 2005, an increase of $8.6 million from $2.9 million in fiscal 2004. This increase resulted primarily from an increase in outstanding borrowings by Atlas Pipeline to fund the acquisitions of Spectrum and Elk City, as well as $1.0 million of accelerated amortization of deferred financing costs associated with the retirement of the term portion of the Atlas Pipeline credit facility in April 2005.

Minority Interests

Year ended December 31, 2006 compared to year ended December 31, 2005

At December 31, 2006, we owned 11% of the partnership interest in Atlas Pipeline through our ownership in AHD. Because we control the operations of AHD, we include it in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest in AHD earnings was $17.7 million for in the year ended December 31, 2006 and $14.3 million for 2005, an increase of $4.0 million for the year. This increase is a result of an increase in the percentage interest of public unit holders and, as discussed above, an increase in Atlas Pipeline's net income.

After the initial public offering of Atlas Energy on December 18, 2006, approximately 19.5% is owned by the general public. Because we control the operations of Atlas Energy, we include it in our consolidated financial statements and show the ownership by the pubic as a minority interest. The minority interest in Atlas Energy was $546,000 for the period from December 18, 2006 (the date of its initial public offering) through December 31, 2006.

Year ended September 30, 2005 compared to year ended September 30, 2004

At September 30, 2005, we owned 18.9% of the partnership interest in Atlas Pipeline through our general partner interest and limited partner units. The limited partner units were subordinated until January 1, 2005, when the subordination term expired and they converted to common units in accordance with the terms of the partnership agreement. Our ownership interest decreased 32% from 51% as a result of the completion by Atlas Pipeline of common unit offerings in May 2003, April and July 2004, and June 2005.

The minority interest in Atlas Pipeline's earnings was $14.8 million for fiscal 2005 and $5.0 million for fiscal 2004, an increase of $9.8 million for the year. The increase was a result of an increase in the percentage interest of public unit holders and an increase in Atlas Pipeline's net income.

Other Income, Net

Our other income was $8.6 million in the year ended December 31, 2006. We received $5.6 million, resulting in a $2.7 million gain, from the sale of certain gathering pipelines within the Atlas Pipeline's Velma gas system and cash proceeds of $7.5 million, resulting in a $2.9 million gain, from an insurance claim settlement related to fire damage at a Velma compressor station sustained during 2006. We also earned $1.3 million in interest income from investments of the $74.3 million distribution received by us from the initial public offering of AHD.

Income Taxes

Our effective income tax rates were 82%, 37%, 38% and 35% in the year ended December 31, 2006, three months ended December 31, 2005 and the years ended September 30, 2005 and 2004. The increase in rates from period to period is a result of a reduction in statutory depletion benefits relative to increased net income and an increase in state income taxes. We received $74.3 million in proceeds associated with an initial public offering of AHD units on July 26, 2006. Although this transaction did not generate a gain in accordance with generally accepted accounting principles, the distribution of the net proceeds of $74.1 million to us generated a taxable gain which resulted in tax charge of $29.8 million, or $1.51, and $1.48 per share-basic and diluted in the year ended December 31, 2006, respectively. We also incurred a $1.2 million income tax charge related to our spin-off from Resource America in the year ended September 30, 2005.

Arbitration settlement-net

In December 30, 2004, Atlas Pipeline entered into a settlement agreement with SEMCO Energy, Inc. settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline Company to Atlas Pipeline. For the years ended September 30, 2005 and 2004, Atlas Pipeline received $4.3 million (net of expenses incurred of $1.2 million) and incurred $3.0 million in expenses which are included in arbitration settlement-net on our statements of income.

Liquidity and Capital Resources

General. We fund operations from a combination of sources. Atlas Energy funds its exploration and production operations from cash generated by operations, capital raised through drilling investment partnerships and, if required, use of its credit facility. Atlas Pipeline funds its operations through a combination of cash generated by operations, its credit facility and sales of its common units.

The following table sets forth our sources and uses of cash for the periods indicated (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Provided by operations	$ 42,324	$ 52,769	$ 112,045	$ 50,043
Used in investing activities	(180,186)	(194,941)	(294,891)	(181,789)
Provided by financing activities	268,108	179,046	171,935	135,566
Increase (decrease) in cash and cash equivalents	$ 130,246	$ 36,874	$ (10,911)	$ 3,820

We had $185.4 million in cash and cash equivalents on hand at December 31, 2006, as compared to $55.2 million at December 31, 2005. Our ratio of earnings from continuing operations before income taxes, minority interest and interest expense to fixed charges was 4.0 to 1.0 for the year ended December 31, 2006, as compared to 6.0 to 1.0 for the year ended December 31, 2005. We had working capital of $77.5 million, an increase of $138.4 million from a deficit of $60.9 at

December 31, 2005. The increase in our working capital reflects an increase in our current assets of $162.8 million, partially offset by an increase in our current liabilities of $24.4 million. The increase in our current assets is primarily due to an increase in cash of $130.2 million. In addition, there was an increase in accounts receivable of $26.3 million, which includes an increase of $18.6 million in the current portion of our hedge receivable. The increase in our current liabilities is primarily due to an increase of $16.3 million in our liabilities associated with drilling contracts, related to an increase in drilling activity associated with our investment partnerships.

Our long-term debt (including current maturities) was 244% of our total capital at December 31, 2006 and 225% at December 31, 2005. This increase is attributable to an additional $35 million in borrowings associated with Atlas Pipeline's senior notes in May 2006. Stockholders' equity increased principally due to net earnings of $16.0 million for the year ended December 31, 2006 and an increase in accumulated other comprehensive income of $14.0 million, partially offset by treasury stock repurchased of $29.9 million during the year.

In December 31, 2006, the borrowing base under Atlas Energy's credit facility was $155.0 million, and it had $154.5 million available. See Note 7 to our Consolidated Financial Statements for information on Atlas Energy and Atlas Pipeline's credit facility at December 2006.

Year Ended December 31, 2006

Cash flows from operating activities. Cash provided by operations is an important source of short-term liquidity for us. Atlas Energy is directly affected by changes in the price of natural gas and oil, interest rates and its ability to raise funds from our drilling investment partnerships. Cash provided by operations is also the primary source of liquidity to fund Atlas Pipeline's quarterly cash distributions and maintenance capital expenditures and is affected by changes in the price of natural gas as a significant portion of Atlas Pipeline's transportation fees are calculated as a percentage of natural gas sale prices. Net cash provided by operating activities was $42.3 million in the year ended December 31, 2006, substantially as a result of the following:

- net income before depreciation, depletion and amortization of $65.5million in fiscal 2006;
- adjustments for non-cash transactions which were added back to cash flows and totaled $26.0 million, including minority interest expense of $18.3 million, non-cash compensation expense related to incentive compensation plans of $10.0 million, less $ 2.3 million in non-cash gain on derivative value;
- changes in operating assets and liabilities increased operating cash flow by $7.6 million in fiscal 2006, primarily due to an increase of $16.3 million in liabilities associated with drilling contracts, partially offset by an increase in accounts receivable and prepaid expense of $13.7 million. Our level of liabilities depends, in part, upon the remaining amount of our drilling obligations at any balance sheet date, which is dependent upon the timing of funds raised through our drilling investment partnerships;
- these increases were partially offset by distributions to minority interest holders of Atlas Pipeline and Atlas Pipeline Holdings of $38.3 million, a gain on asset dispositions of $5.7 million, and $3.8 million of cumulative effect of accounting change.

Cash flows from investing activities. Net cash used in our investing activities during the year ended December 31, 2006 was $180.2 million principally as a result of the following:

- cash used for business acquisitions was $30.0 million, for the acquisition of the remaining 25% equity ownership in NOARK; and
- capital expenditures for oil and gas properties and gas gathering expansions were $159.5 million, partially offset by $9.1 million in proceeds from the sale of assets, consisting principally of certain gathering pipelines in our Mid-Continent operations.

Cash flows from financing activities. Net cash provided by our financing activities during the year ended December 31, 2006 was $268.1 million, principally as a result of the following:

- we received net proceeds of $139.9 million in December 2006 from initial public offerings of Atlas Energy and $74.3 million from the initial public offering of AHD in July 2006;
- Atlas Pipeline received net proceeds of $59.6 million from the issuance of preferred and common units; and $36.6 million from the issuance of additional senior notes;
- net borrowings decreased cash flows by $10.6 million in 2006, principally as a result of the issuance by Atlas Pipeline of additional senior notes in May 2006; and
- We repurchased common stock at a cost of $29.9 million.

Year Ended September 30, 2005 Compared to Year Ended September 30, 2004

Cash flows from operating activities. Net cash provided by operating activities increased $62.0 million in fiscal 2005 to $112.0 million from $50.0 million in fiscal 2004, substantially as a result of the following:

- changes in operating assets and liabilities increased operating cash flow by $41.4 million in fiscal 2005, compared to fiscal 2004, primarily due to increases in accounts payable and accrued liabilities. Our level of liabilities depends upon the remaining amount of our drilling obligations at any balance sheet date, which depends upon the timing of funds raised through our drilling investment partnerships;
- an increase in net income before depreciation, depletion and amortization of $23.7 million in fiscal 2005 as compared to the prior fiscal year principally a result of higher natural gas prices and drilling profits;
- a decrease in minority interest of $1.0 million due to an increase in Atlas Pipeline's earnings and common units outstanding held by the public and an increase in earnings in fiscal 2005 as compared to 2004; and
- a decrease in non-cash items included in net income which were added back to cash flows totaled $2.4 million. These include $3.0 million of terminated acquisition costs, $2.5 million of gains on derivative value, less $3.0 million of non-cash compensation awards.

Cash flows from investing activities. Net cash used in our investing activities increased $113.1 million in fiscal 2005 to $294.9 million from $181.8 million in fiscal 2004 as a result of the following:

- cash used for business acquisitions increased $53.7 million; and
- capital expenditures increased $58.0 million due to an increase in the number of wells we drilled, as well as an expansion of our Mid-Continent gathering systems and processing facilities.

Cash flows from financing activities. Net cash provided by our financing activities increased $36.3 million in fiscal 2005 to $171.9 million from $135.6 million in fiscal 2004, as a result of the following:

- payments to RAI in the form of repayments of advances and dividends decreased by $22.0 million, principally as a result of a one-time special dividend paid in fiscal 2004 as part of the transactions leading to our spin-off from RAI; and
- net borrowings increased cash flows by $51.9 million in fiscal 2005 as compared to the prior fiscal year principally as a result of borrowings associated with the acquisition of Elk City.
- these increases were partially offset by proceeds we received of $37.0 million in fiscal 2004 from the public offering of our common stock; there were no offerings in fiscal 2005

Capital requirements. During the year ended December 31, 2006, our capital expenditures related primarily to acquisitions, investments in our drilling investment partnerships and pipeline expansions, in which we invested $30.0 million, $75.6 million and $83.8 million, respectively. During fiscal 2006, we funded capital expenditures through cash on hand, borrowings under our credit facilities, and from operations. We have established three credit facilities to facilitate the funding of our capital expenditures.

The level of capital expenditures Atlas Energy must devote to its exploration and production operations depends upon the level of funds raised through its drilling investment partnerships. During the year ended December 31, 2006 we raised $218.5 million. We believe cash flow from operations and amounts available under Atlas Energy's credit facility will be adequate to fund its contributions to these partnerships. However, the amount of funds Atlas Energy raises and the level of its capital expenditures will vary in the future depending on market conditions for natural gas and other factors.

We continuously evaluate acquisitions of gas and oil and pipeline assets. In order to make any acquisition, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. We cannot assure you that we will be successful in our efforts to obtain outside capital.

Changes in Prices and Inflation

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms and our ability to finance our drilling activities through drilling investment partnerships have been and will continue to be affected by changes in oil and gas prices. Natural gas and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. During the year ended December 31, 2006, we received an average of $8.83 per mcf of natural gas and $62.30 per bbl of oil as compared to $8.34 per mcf and $53.22 per bbl in fiscal 2005 and $5.84 per mcf and $32.85 per bbl in fiscal 2004.

Although certain of our costs and expenses are affected by general inflation, inflation has not normally had a significant effect on us. However, inflationary trends may occur if the price of natural gas were to increase since such an increase may increase the demand for acreage and for energy equipment and services, thereby increasing the costs of acquiring or obtaining such equipment and services.

Environmental Regulation

To date, compliance with environmental laws and regulations has not had a material impact on our capital expenditures, earnings or competitive position. We cannot assure you that compliance with environmental laws and regulations will not, in the future, increase our costs of doing business or restrictions on the manner in which we conduct our operations.

Dividends

We did not pay dividends in the year ended December 31, 2006. In the year ended September 30, 2004 we paid dividends of $52.1 million to our former parent. The determination of the amount of future cash dividends, if any, is at the sole discretion of our board of directors and will depend on the various factors affecting our financial condition and other matters the board of directors deems relevant.

Contractual Obligations and Commercial Commitments

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

		Payments Due By Period (in thousands)			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 – 3 Years**	**4 – 5 Years**	**After 5 Years**
Long-term debt	$ 324,151	$ 109	$ 65	$ 38,000	$ 285,977
Secured revolving credit facilities	—	—	—	—	—
Operating lease obligations	8,166	4,318	3,467	380	1
Capital lease obligations	—	—	—	—	—
Unconditional purchase obligations	—	—	—	—	—
Other long-term obligations	—	—	—	—	—
Total contractual cash obligations	$ 332,317	$ 4,427	$ 3,532	$ 38,380	$ 285,978

Not included in the table above are estimated interest payments calculated at the rates in effect at December 31, 2006: less than one year - $26.4 million; 1 to 3 years - $52.9 million; 4 to 5 years - $51.3 million; after 5 years - $93.3 million.

		Payments Due By Period (in thousands)			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 – 3 Years**	**4 – 5 Years**	**After 5 Years**
Standby letters of credit	$ 8,545	$ 8,520	$ 25	$ —	$ —
Guarantees	—	—	—	—	—
Standby replacement commitments	—	—	—	—	—
Other commercial commitments	34,844	34,844	—	—	—
Total commercial commitments	$ 43,389	$ 43,364	$ 25	$ —	$ —

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of our assets, liabilities, revenues and cost and expenses, and related disclosure of contingent assets and liabilities. On an on-going basis, we evaluate our estimates, including those related to the provision for possible losses, deferred tax assets and liabilities, goodwill and identifiable intangible assets, and certain accrued liabilities. We base our estimates on historical experience and on various other assumptions that we believe reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

We have identified the following policies as critical to our business operations and the understanding of our results of operations.

Accounts Receivable and Allowance for Possible Losses.

Through our business segments, we engage in credit extension, monitoring, and collection. In evaluating our allowance for possible losses, 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 our customer's credit information. We extend credit on an unsecured basis to many of our energy customers. At December 31, 2006, our credit evaluation indicated that we have no need for an allowance for possible losses for our oil and gas receivables.

Reserve Estimates

Our estimates of Atlas Energy's proved natural gas and oil reserves and future net revenues from them are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant variance in these assumptions could materially affect the estimated quantity of Atlas Energy's reserves. As a result, our estimates of Atlas Energy's proved natural gas and oil reserves are inherently imprecise. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves may vary substantially from Atlas Energy's estimates or estimates contained in the reserve reports and may affect our ability to pay amounts due under our credit facilities or cause a reduction in our credit facilities. In addition, Atlas Energy's proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, mechanical difficulties, governmental regulation and other factors, many of which are beyond our control.

Impairment of Oil and Gas Properties

We review Atlas Energy's producing oil and gas properties for impairment on an annual basis and whenever events and circumstances indicate a decline in the recoverability of their carrying values. We estimate the expected future cash flows from our oil and gas properties and compare such future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and gas properties to their fair value in the current period. The factors used to determine fair value include, but are not limited to, estimates of reserves, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. Because of the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that will require us to record an impairment of our oil and gas properties. Any such impairment may affect or cause a reduction in our credit facilities.

Dismantlement, Restoration, Reclamation and Abandonment Costs

On an annual basis, we estimate the costs of future dismantlement, restoration, reclamation and abandonment of our natural gas and oil-producing properties. We also estimate the salvage value of equipment recoverable upon abandonment. On December 31, 2006 we adopted the Financial Accounting Standards Board, or FASB, Interpretation No. 47, or FIN 47, *Accounting for Conditional Asset Retirement Obligations*, as discussed in Note 2 to our consolidated financial statements. As of December 31, 2006, and 2005, our estimate of salvage values was greater than or equal to our estimate of the costs of future dismantlement, restoration, reclamation and abandonment. A decrease in salvage values or an increase in dismantlement, restoration, reclamation and abandonment costs from those we have estimated, or changes in our estimates or costs, could reduce our gross profit from operations.

Goodwill and Other Long-Lived Assets

Goodwill and other intangibles with an indefinite useful life are no longer amortized, but instead are assessed for impairment annually. We have recorded goodwill of $98.6 million in connection with several acquisitions of assets. In assessing impairment of goodwill, we use estimates and assumptions in estimating the fair value of reporting units. If under these estimates and assumptions we determine that the fair value of a reporting unit has been reduced, the reduction can result in an "impairment" of goodwill. However, future results could differ from the estimates and assumptions we use. Events or circumstances which might lead to an indication of impairment of goodwill would include, but might not be limited to, prolonged decreases in expectations of long-term well servicing and/or drilling activity or rates brought about by prolonged decreases in natural gas or oil prices, changes in government regulation of the natural gas and oil industry or other events which could affect the level of activity of exploration and production companies.

In assessing impairment of long-lived assets other than goodwill, where there has been a change in circumstances indicating that the carrying amount of a long-lived asset may not be recoverable, we have estimated future undiscounted net cash flows from the use of the asset based on actual historical results and expectations about future economic circumstances, including natural gas and oil prices and operating costs. Our estimate of future net cash flows from the use of an asset could change if actual prices and costs differ due to industry conditions or other factors affecting our performance.

Revenue Recognition

Exploration and Development

Atlas Energy conducts certain activities through, and a portion of its revenues are attributable to, sponsored energy limited partnerships. These energy partnerships raise capital from investors to drill gas and oil wells. Atlas Energy serves as general partner of the energy partnerships and assumes customary rights and obligations for them. As the general partner, it is liable for partnership liabilities and can be liable to limited partners if it breaches responsibilities with respect to the operations of the partnerships. The income from Atlas Energy's general partner interest is recorded when the gas and oil are sold by a partnership.

Atlas Energy contracts with the energy partnerships to drill partnership wells. The contracts require that the energy partnerships must pay the full contract price upon execution. The income from a drilling contract is recognized as the services are performed using the percentage of completion method. The contracts are typically completed in less than 60 days. We classify the difference between the contract payments Atlas Energy has received and the revenue earned as a current liability, included in liabilities associated with drilling contracts.

Atlas Energy recognizes gathering, transmission and processing revenues at the time the natural gas is delivered to the purchaser.

Atlas Energy recognizes well services revenues at the time the services are performed.

Atlas Energy is entitled to receive management fees according to the respective partnership agreements. Atlas Energy recognizes such fees as income when earned and includes them in well services revenues.

Atlas Energy records the income from the working interests and overriding royalties of wells it owns an interest in when the gas and oil are delivered.

Transmission, Gathering and Processing

Atlas Pipeline's Mid-Continent revenue is determined primarily by the fees earned from its transmission, gathering and processing operations. Revenue associated with Atlas Pipeline'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 Atlas Pipeline's gathering and processing operations are based on percentage-of-proceeds ("POP") and fixed-fee contracts. Under its POP purchasing arrangements, Atlas Pipeline 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.

Revenue in the Appalachian segment is recognized at the time the natural gas is transported through Atlas Pipeline's gathering systems. Substantially all 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 $0.45 per Mcf, depending on the ownership of the well.

Income Taxes

As part of the process of preparing consolidated financial statements, we are required to estimate income taxes in each of the jurisdictions in which we operate. Significant judgment is required in determining the income tax expense provision. We recognize deferred tax assets and liabilities based on differences between the financial reporting and tax bases of assets and liabilities using the enacted tax rates and laws that are expected to be in effect when the differences are expected to be recovered. We assess the likelihood of our deferred tax assets being recovered from future taxable income. We then provide a valuation allowance for deferred tax assets for which we do not consider realization of such assets to be more likely than not. We consider future taxable income and ongoing prudent and feasible tax planning strategies in assessing the valuation allowance. Any decrease in the valuation allowance could have a material impact on net income in the period in which such determination is made.

Recently Issued Financial Accounting Standards

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, or* 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 the impact of the adoption of SFAS 159 on our financial position and results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employer's Accounting for Defined Benefit Pension and Other Post Retirement Plans, or* SFAS 158. SFAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan as an asset or liability, by recording the difference between the plan assets fair value and the benefit obligation. The employer must recognize after-tax gains and losses as a result of changes in the funded status as a component of other comprehensive income. The employer is also required to measure the funded status of a plan as of the date of its year end statements, and disclose in the notes to the statements additional information regarding the net periodic benefit costs. SFAS 158 is effective for us for the year ended December 31, 2006. The adoption of SFAS 158 did not have a significant impact on our financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS 157. SFAS 157 addresses the need for increased consistency in fair value measurements, defining fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It also establishes a framework for measuring fair value and expands disclosure requirements. SFAS 157 is effective for us beginning January 1, 2008. We are currently evaluating the impact of the adoption of SFAS 157 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 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. SAB 108 is effective for fiscal years ending on or after November 15, 2006.

Traditionally, there have been two widely-recognized methods for quantifying the effects of financial statement misstatements: the "roll-over" method and the "iron curtain" method. The roll-over method focuses primarily on the impact of a misstatement on the income statement, including the reversing effect of prior year misstatements, but its use can lead to the accumulation of misstatements in the balance sheet. The iron-curtain method, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. Prior to the Company's application of the guidance in SAB 108, the Company used the roll-over method for quantifying identified financial statement misstatements and concluded that they were immaterial individually and in the aggregate.

With SAB 108, the SEC staff established an approach that requires quantification of financial statement misstatements based on the effects of the misstatements on each of the company's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it requires quantification of errors under both the iron curtain and the roll-over methods.

SAB 108 permits existing public companies to initially apply its provisions either by (i) restating prior financial statements as if the "dual approach" had always been applied or (ii) recording the cumulative effect of initially applying the "dual approach" as adjustments to the carrying values of assets and liabilities as of the beginning of a Company's fiscal year, with an offsetting adjustment recorded to the opening balance of retained earnings. The Company elected to record the effects of applying SAB 108 using the cumulative effect transition method to its accounting practice for recording incentive compensation for its executive officers and other employees which it historically recognized in the year in which it was paid. Concurrent with the Company's change in year-end from September 30 to December 31, the Company adopted the provisions of SAB 108, and recorded an increase in accrued liabilities in the amount of $4.0 million, a decrease in accrued income taxes of $1.6 million and a reduction of retained earnings of approximately $2.4 million as of January 1, 2006.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements and provides guidance on the recognition, de-recognition and measurement of benefits related to an entity's uncertain tax positions. FIN 48 is effective for us beginning January 1, 2007. We do not expect the adoption of FIN 48 to have a significant impact on our financial position or results of operations.

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 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

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 periodically use derivative financial instruments such as forward contracts and interest rate cap and swap agreements.

The following analysis presents the effect on our earnings, cash flows and financial position as if hypothetical changes in market risk factors occurred on December 31, 2006. Only the potential impacts 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, Atlas Energy had no outstanding borrowings under its $200 million credit facility. Borrowings under its credit facility are subject to movements in interest rates and could impact our net income and cash flows.

At December 31, 2006, Atlas Pipeline had a $225 million revolving credit facility of which $130 million was outstanding. The weighted average interest rate for borrowings under this credit facility was 7.6% at December 31, 2006. Holding all other variables constant, a hypothetical 10% change in the weighted average interest rate would change our net income by approximately $19,400.

Commodity Price Risk. Our major market risk exposure in commodities is fluctuations in the price of natural gas and oil. To limit our exposure to changing natural gas prices, we use financial hedges for a portion of our projected natural gas production. Atlas America's commodity risk is based on that of its major subsidiaries, Atlas Energy Resources ("Atlas Energy") and Atlas Pipeline.

Atlas Energy Resources. Realized pricing of Atlas Energy's oil and gas production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas production. Pricing for gas and oil production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas prices, we use forward sales contracts. Through our hedges, we seek to provide a measure of stability in the volatile environment of natural gas prices. These transactions are similar to NYMEX-based futures contracts, swaps and options, but also require firm delivery of the hedged quantity. Thus, we limit these arrangements to much smaller quantities than those projected to be available at any delivery point.

Atlas Energy negotiates with certain purchasers for delivery of a portion of natural gas they produce for the upcoming year. The prices under most of their gas sales contracts are negotiated on an annual basis and are index-based. Their risk management objective is to lock in a range of pricing for expected production volumes. Considering those volumes for which they have entered into physical or financial hedge agreements for the twelve month period ending December 31, 2007, and current indices, a theoretical 10% upward or downward change in the price of natural gas would result in a change in net income of approximately $2.2 million.

We also enter into natural gas futures and option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. A portion of the future sales is periodically hedged through the use of swaps and collar contracts.

We formally document all relationships between hedging instruments and the items being hedged, including the 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 highly effective in offsetting changes in the fair value of hedged items. Historically these contracts have qualified and been designated as cash flow hedges and recorded at their fair values. Gains or losses on future contracts are determined as the difference between the contract price and a reference price, generally prices on NYMEX. Changes in fair value are recognized in combined equity and recognized within the combined statements of income in the month the hedged commodity is sold. If it is determined that a derivative is not highly effective as a hedge or it has ceased to be a highly effective hedge, due to the loss of correlation between changes in reference prices underlying a hedging instrument and actual commodity prices, we will discontinue hedge accounting for the derivative and subsequent changes in fair value for the derivative will be recognized immediately into earnings.

For the twelve month period ending December 31, 2007, we have hedged, through both physical and financial hedges, approximately 77% of our projected natural gas volumes. At December 31, 2006, we had allocated to us 234 open natural gas futures contracts related to natural gas sales covering 54.9 million MMBtus of natural gas, maturing through December 31, 2010 at a combined average settlement price of $8.48 per MMBtu. We recognized a gain of $7.1 million on settled contracts covering natural gas production for the year ended December 31, 2006. We recognized no gains or losses during the year ended December 31, 2006 for hedge ineffectiveness or as a result of the discontinuance of these cash flow hedges. We recognized no gains or losses for the three months ended December 31, 2005 or the years ended September 30, 2005 or 2004 related to hedges. Of the $47.5 million net unrealized hedge gain, our portion is $21.1 million and $26.4 million has been reallocated to our investment partnerships.

Atlas Pipeline. The commodity price risk that Atlas Pipeline is exposed to is 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, natural gas liquids, or NGLs, 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 ended December 31, 2007 of approximately $5.3 million.

We enter into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133 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 a fixed price and remit a floating price based on certain indices for the relevant contract period.

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 our consolidated statements of income.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. At December 31, 2006, Atlas Pipeline had a net hedging liability of $20.1 million. 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 our consolidated statements of income as they occur. Ineffective hedge gains or losses are recorded within natural gas and liquids revenue in our consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. Atlas Pipeline recognized losses of $13.9 million, $5.6 million, $5.0 million, and $27,000 for the year ended December 31, 2006, three months ended December 31, 2005, and twelve months ended September 30, 2005 and 2004, respectively, within our consolidated statements of income related to the settlement of qualifying hedge instruments. Atlas Pipeline also recognized gains of $5.7 million, losses of $320,000, $64,000, and $697,000 for the year ended December 31, 2006, three months ended December 31, 2005, and twelve months ended September 30, 2005 and 2004, respectively, within our consolidated statements of income related to the change in market value of non-qualifying or ineffective hedges.

A portion of our future natural gas 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

Atlas America. At December 31, 2006 and December 31, 2005, we reflected a net hedging asset and liability on our balance sheets of $27.3 million and $41.5 million, respectively, as a result of Atlas Energy and Atlas Pipeline hedges. Of the $8.8 million net gain in accumulated other comprehensive income at December 31, 2006, we will reclassify $5.2 million of gains to our consolidated statements of income over the next twelve month period as these contracts expire, and $3.6 million of gains will be reclassified in later periods if the fair values of the instruments remain at current market values. Actual amounts that will be reclassified will vary as a result of future price changes.

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

ATLAS ENERGY RESOURCES HEDGES

Fixed Price Swaps

Twelve Month Period Ending December 31	Volumes	Average Fixed Price	Fair Value Asset (3)
	(MMBTU) (1)	(per MMBTU)	(in thousands)
2007	14,650,000	$ 8.596	$ 25,935
2008	15,800,000	8.914	11,450
2009	15,720,000	8.306	7,690
2010	5,400,000	7.532	587
			$ 45,662

Costless Collars

Twelve Month Period Ending December 31	Option Type	Volumes	Average Floor and Cap	Fair Value Asset (3)
		(MMBTU)	(per MMBTU)	(in thousands)
2007	Puts purchased	1,800,000	$ 7.50 – 8.60	$ 1,511
2007	Calls sold	1,800,000	7.50 – 8.60	—
2008	Puts purchased	1,560,000	7.50 – 9.40	281
2008	Calls sold	1,560,000	7.50 – 9.40	—
				$ 1,792

ATLAS PIPELINE HEDGES

Natural Gas Liquids Fixed – Price Swaps

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

Natural Gas Fixed – Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Asset/(Liability)(3)
	(MMBTU)(1)	(per MMBTU)	(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 Swaps

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

Natural Gas Fixed Price (Purchase)

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability [3]
	(MMBTU) [1]	(per MMBTU)	(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 (Purchase)

Production Period Ended December 31,		Volumes	Average Fixed Price	Fair Value Liability [3]
		(MMBTU) [1]	(per MMBTU)	(in thousands)
2007		6,960,000	$ (0.903)	$ (54)
2008		3,336,000	(1.042)	(63)
2009		2,400,000	(0.600)	(59)
				$ (176)

Crude Oil Fixed – Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability[3]
	(barrels)	(per barrel)	(in thousands)
2007	77,900	$ 56.175	$ (670)
2008	65,400	59.424	(526)
2009	33,000	62.700	(148)
			$ (1,344)

Crude Oil Options

Production Period Ended December 31,	Option Type	Volumes	Average Strike Price	Fair Value Asset/(Liability)[3]
		(barrels)	(per barrel)	(in thousands)
2007	Puts purchased	13,200	$ 60.00	$ 33
2007	Calls sold	13,200	73.38	(26)
2008	Puts purchased	17,400	60.00	71
2008	Calls sold	17,400	72.78	(85)
2009	Puts purchased	30,000	60.00	147
2009	Calls sold	30,000	71.25	(178)
				$ (38)

Crude Oil Sales Options

Production Period Ended December 31,	Option Type	Volumes	Average Strike Price	Fair Value Asset(3)
		(barrels)	(per barrel)	(in thousands)
2008	Puts purchased	720,000	$ 60.00	$ 2,919
2008	Calls sold	720,000	84.00	(1,508)
2009	Puts purchased	720,000	60.00	3,527
2009	Calls sold	720,000	81.00	(2,272)
				$ 2,666
		Total net asset		$ 27,329

(1) MMBTU represents million British Thermal Units.

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

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

(4) Includes Atlas Pipeline'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 Atlas Pipeline'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.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Atlas America, Inc.

We have audited the accompanying consolidated balance sheets of Atlas America, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, changes in stockholder's equity, and cash flows for the year ended December 31, 2006, the three month period ended December 31, 2005, and for the years ended September 30, 2005 and 2004. These financial statements are the responsibility of the Company'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 America, Inc. and subsidiaries as of December 31, 2006 and 2005 and the results of their operations and cash flows for the year ended December 31, 2006, the three month period ended December 31, 2005, and for the years ended September 30, 2005 and 2004, 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 America, Inc.'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 February 28, 2007 expressed an unqualified opinion thereon.

As discussed in Note 2 to the consolidated financial statements, effective October 1, 2005, the Company adopted SFAS No. 123(R), "Share-Based Payment," as revised.

As also discussed in Note 2 to the consolidated financial statements, the Company recorded a cumulative effect adjustment in connection with the adoption of FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."

/s/ GRANT THORNTON LLP

Cleveland, Ohio
February 28, 2007

ATLAS AMERICA, INC.
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 185,401	$ 55,155
Accounts receivable	116,104	89,830
Prepaid expenses	13,738	5,772
Deferred tax asset	5,022	6,249
Advances to affiliate	—	492
Total current assets	320,265	157,498
Property and equipment, net	884,812	658,347
Intangible assets, net	30,741	60,959
Other assets, net	42,501	32,832
Goodwill	98,607	146,544
	$ 1,376,926	$ 1,056,180
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 109	$ 1,351
Accounts payable	56,438	56,769
Liabilities associated with drilling contracts	86,765	70,514
Accrued producer liabilities	32,766	32,537
Accrued hedge liability	17,363	24,107
Accrued liabilities	49,207	33,091
Advances from affiliate	117	—
Total current liabilities	242,765	218,369
Long-term debt	324,042	297,430
Deferred tax liability	30,190	29,369
Other liabilities	52,996	54,865
Minority interest	594,687	323,297
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, $0.01 par value: 1,000,000 authorized shares	—	—
Common stock, $0.01 par value: 49,000,000 authorized shares	200	133
Additional paid-in capital	77,447	75,967
Treasury stock, at cost	(29,349)	(73)
ESOP loan receivable	(490)	(564)
Accumulated other comprehensive income (loss)	8,426	(5,116)
Retained earnings	76,012	62,503
Total stockholders' equity	132,246	132,850
	$ 1,376,926	$ 1,056,180

See accompanying notes to consolidated financial statements

ATLAS AMERICA, INC.
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
REVENUES				
Gas and oil production	$ 88,449	$ 24,086	$ 63,499	$ 48,526
Well construction and completion	198,567	42,145	134,338	86,880
Transmission, gathering and processing	437,575	128,740	264,716	34,228
Administration and oversight	11,762	2,964	9,875	8,396
Well services	12,953	2,561	9,552	8,430
	749,306	200,496	481,980	186,460
COSTS AND EXPENSES				
Well construction and completion	172,666	36,648	116,816	75,548
Gas and oil production	8,499	1,721	6,044	5,265
Transmission, gathering and processing	361,045	109,889	229,816	27,870
Well services	7,337	1,487	5,167	4,399
General and administrative	46,517	9,453	23,961	14,971
Net expense reimbursement - affiliate	1,237	163	602	1,050
Depreciation, depletion and amortization	45,643	10,324	24,895	14,700
	642,944	169,685	407,301	143,803
OPERATING INCOME	106,362	30,811	74,679	42,657
OTHER INCOME (EXPENSE)				
Interest expense	(27,313)	(6,147)	(11,467)	(2,881)
Minority interests	(18,283)	(6,745)	(14,773)	(4,961)
Arbitration settlement, net	—	—	4,290	(2,987)
Other, net	8,564	691	229	768
	(37,032)	(12,201)	(21,721)	(10,061)
Income before income taxes and cumulative effect of accounting change	69,330	18,610	52,958	32,596
Provision for income taxes	(27,308)	(6,886)	(20,018)	(11,409)
Tax on gain on sale of Atlas Pipeline Holdings, L.P.	(29,846)	—	—	—
	(57,154)	(6,886)	(20,018)	(11,409)
Net income before cumulative effect of accounting change	$ 12,176	$ 11,724	$ 32,940	$ 21,187
Cumulative effect of accounting change (net of tax of $2,530)	3,825	—	—	—
Net income	$ 16,001	$ 11,724	$ 32,940	$ 21,187
Net income per common share – basic				
Net income before cumulative effect of accounting change-basic	$ 0.62	$ 0.59	$ 1.65	$ 1.21
Cumulative effect of accounting change	0.19	—	—	—
	$ 0.81	$ 0.59	$ 1.65	$ 1.21
Weighted average common shares outstanding - basic	19,716	20,003	20,001	17,525
Net income per common share – diluted				
Net income before cumulative effect on accounting change - diluted	$ 0.60	$ 0.58	$ 1.64	$ 1.21
Cumulative effect of accounting change	0.19	—	—	—
	$ 0.79	$ 0.58	$ 1.64	$ 1.21
Weighted average common shares outstanding - diluted	20,157	20,213	20,049	17,526

See accompanying notes to consolidated financial statements

ATLAS AMERICA, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Net income	$ 16,001	$ 11,724	$ 32,940	$ 21,187
Other comprehensive income (loss):				
Unrealized holding gains (losses) on hedging contracts, net of tax of ($8,631), $653, $2,452 and $1,384	14,155	(1,112)	(4,360)	(2,571)
Additional postretirement plan liability recorded upon adoption of FASB 158, net of tax of $267	(416)			
Less: reclassification adjustment for hedge (gains) losses realized in net income, net of tax of $127, ($946), ($730) and ($10)	(197)	1,611	1,298	18
	13,542	499	(3,062)	(2,553)
Comprehensive income	$ 29,543	$ 12,223	$ 29,878	$ 18,634

See accompanying notes to consolidated financial statements

ATLAS AMERICA, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(in thousands, except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	ESOP Loan Receivable	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity
Balance, September 30, 2003	10,688,333	$ 107	$ 38,619	-	$ -	$ -	$ -	$ 48,785	$ 87,511
Initial public offering, net of costs	2,645,000	26	36,965	-	-	-	-	-	36,991
Dividend to parent	-	-	-	-	-	-	-	(52,133)	(52,133)
Other comprehensive income	-	-	-	-	-	-	(2,553)	-	(2,553)
Net income	-	-	-	-	-	-	-	21,187	21,187
Balance, September 30, 2004	13,333,333	$ 133	$ 75,584	-	$ -	$ -	$ (2,553)	$ 17,839	$ 91,003
Issuance of common stock	1,370	-	53	-	-	-	$ -	-	53
Other comprehensive income	-	-	-	-	-	-	(3,062)	-	(3,062)
Loan to ESOP	-	-	-	-	-	(602)	-	-	(602)
Repayment of ESOP loan	-	-	-	-	-	19	-	-	19
Net income	-	-	-	-	-	-	-	32,940	32,940
Balance, September 30, 2005	13,334,703	$ 133	$ 75,637	-	$ -	$ (583)	$ (5,615)	$ 50,779	$ 120,351
Issuance of common stock	1,328	-	64	-	-	-	-	-	64
Other comprehensive income	-	-	-	-	-	-	499	-	499
Employee stock option plan	-	-	266	-	-	-	-	-	266
Repayment of ESOP loan	-	-	-	-	-	19	-	-	19
Treasury stock purchase	-	-	-	(1,335)	(73)	-	-	-	(73)
Net income	-	-	-	-	-	-	-	11,724	11,724
Balance, December 31, 2005	13,336,031	$ 133	$ 75,967	(1,335)	$ (73)	$ (564)	$ (5,116)	$ 62,503	$ 132,850
Cumulative effect adjustment for adoption of SAB 108 (net of tax of 1,575)	-	-	-	-	-	-	-	(2,425)	(2,425)
Restated Balance, January 1, 2006	13,336,031	$ 133	75,967	(1,335)	$ (73)	(564)	$ (5,116)	$ 60,078	$ 130,425
Issuance of common stock	7,790	-	100	9,542	580	-	-	-	680
Other comprehensive income	-	-	-	-	-	-	13,542	-	13,542
Repayment of ESOP loan	-	-	-	-	-	74	-	-	74
Treasury stock purchase	-	-	-	(667,342)	(29,856)	-	-	-	(29,856)
Stock option compensation	-	-	1,425	-	-	-	-	-	1,425
Three-for-two stock split	6,664,598	67	(45)	-	-	-	-	(67)	(45)
Net income	-	-	-	-	-	-	-	16,001	16,001
Balance, December 31, 2006	20,008,419	$ 200	$ 77,447	(659,135)	$ (29,349)	$ (490)	$ 8,426	$ 76,012	$ 132,246

See accompanying notes to consolidated financial statements

ATLAS AMERICA, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income before taxes	$ 16,001	$ 11,724	$ 32,940	$ 21,187
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	45,643	10,324	24,895	14,700
Amortization of deferred finance costs	3,818	544	2,448	704
Non-cash loss (gain) on derivative value	(2,316)	138	(1,887)	585
Non-cash compensation on long-term incentive plans	9,961	1,320	3,467	407
Terminated acquisition	—	—	—	2,987
Cumulative effect of change in accounting principle	(3,825)	—	—	—
Minority interests.	18,283	6,745	14,773	4,961
Gain on asset dispositions	(5,679)	(2)	(104)	(39)
Distributions paid to minority interests	(38,276)	(6,381)	(18,073)	(7,271)
Deferred income taxes	(8,921)	1,033	2,275	1,896
Changes in operating assets and liabilities:				
(Increase) decrease in accounts receivable and prepaid expenses	(13,726)	(3,804)	(38,067)	8,689
Increase (decrease) in accounts payable and accrued liabilities	18,809	24,797	89,268	1,237
Increase (decrease) in accounts payable / receivable from affiliates	2,552	6,331	110	0
Net cash provided by operating activities of continuing operations	42,324	52,769	112,045	50,043
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures	(159,466)	(31,809)	(99,185)	(41,162)
Business acquisitions, net of cash acquired	(30,000)	(163,630)	(195,262)	(141,564)
Proceeds from disposal of assets	9,109	3	170	405
Decrease (increase) in other assets	171	495	(614)	532
Net cash used in investing activities	(180,186)	(194,941)	(294,891)	(181,789)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Borrowings	157,250	216,841	385,750	183,532
Principal payments on borrowings	(167,857)	(399,367)	(279,590)	(129,319)
Issuance of Atlas America, Inc. common stock	—	—	—	36,991
Net proceeds from the sale of Atlas Energy Resources, LLC initial public offering	139,944	—	—	—
Net proceeds from the sale of Atlas Pipeline Holdings, L.P. initial public offering	74,326	—	—	—
Net proceeds from issuance of Atlas Pipeline Partners, L.P. common and preferred units	59,585	120,980	91,720	92,714
Issuance of Atlas Pipeline Partners L.P. senior notes	36,582	243,102	—	—
Purchase of treasury shares	(29,856)	—	—	—
Dividend to Resource America	—	—	—	(52,133)
Advances from (payments to) parent	—	—	(22,431)	7,702
Increase in other assets	(1,866)	(2,510)	(3,514)	(3,921)
Net cash provided by financing activities	268,108	179,046	171,935	135,566
Increase (decrease) in cash and cash equivalents	130,246	36,874	(10,911)	3,820
Cash and cash equivalents at beginning of period	55,155	18,281	29,192	25,372
Cash and cash equivalents at end of period	$ 185,401	$ 55,155	$ 18,281	$ 29,192

See accompanying notes to consolidated financial statements

ATLAS AMERICA, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2006

NOTE 1 — NATURE OF OPERATIONS

Company Overview

Atlas America, Inc. (the "Company" or "AAI and its subsidiaries") was incorporated in Delaware on September 27, 2000 as a wholly-owned indirect subsidiary of Resource America, Inc. ("RAI") (NASDAQ:REXI). In May 2004, the Company completed an initial public offering of 2,645,000 shares of its common stock at a price of $15.50 per common share including underwriters' over allotment. The net proceeds of the offering of $37.0 million, after deducting underwriting discounts and costs, were distributed to RAI in the form of a non-taxable dividend. Following the offering, RAI owned approximately 80.2% of the Company's outstanding common stock. The Company trades under the symbol ATLS on the NASDAQ system.

In December 2006, the Company contributed substantially all of its natural gas and oil assets and its investment partnership management business to Atlas Energy Resources, LLC (NYSE: ATN) ("Atlas Energy"), a then wholly-owned subsidiary. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a 19.5% ownership interest, in an initial public offering at a price of $21.00 per unit. The net proceeds of approximately $139.9 million after underwriting discounts and commissions were distributed to the Company. After completion of the offering, the Company owns approximately 78.5% of Atlas Energy. Additionally, the Company owns Atlas Energy Management, Inc., which owns 2% of the membership interests and all of the management incentive interests in Atlas Energy.

Atlas Energy is an energy company engaged primarily in the development and production of natural gas and, to a lesser extent, oil in the western New York, eastern Ohio, western Pennsylvania and Tennessee region of the Appalachian Basin for its own account and for investors through the offering of tax-advantaged investment programs. The Company has been involved in the energy industry since 1968. The Company began to expand our operations at the end of 1998 when it acquired The Atlas Group, Inc. and a year later when it acquired Viking Resources Corporation, both energy finance and production companies.

In July 2006, the Company contributed its ownership interests in Atlas Pipeline Partners GP, LLC ("Atlas Pipeline GP"), its then wholly-owned subsidiary, and the general partner of Atlas Pipeline Partners, L.P. (NYSE: APL) ("APL"), to Atlas Pipeline Holdings, L.P (NYSE: AHD) ("AHD"). Concurrent with this transaction, AHD issued 3,600,000 common units, representing a 17.1% ownership interest in it, in an initial public offering at a price of $23.00 per unit. The net proceeds of approximately $74.3 million after underwriting discounts and commissions were distributed to the Company.

AHD, through its ownership of Atlas Pipeline GP, the general partner of APL, owns a 2% general partner interest and 1,641,026 common units constituting a 11.4% limited partner interest for a total partnership interest of 13.4% in APL. Because AHD controls the decisions and operations of Atlas Pipeline, Atlas Pipeline is consolidated in the Company's financial statements. APL owns and operates approximately 1,900 miles of active intrastate gas gathering pipeline and a 565-mile interstate natural gas pipeline. Atlas Pipeline also operates three gas processing plants in Velma, Elk City, and Sweetwater, Oklahoma and a treating facility in Prentiss, Oklahoma where natural gas liquids and impurities are removed. In Appalachia, it owns and operates approximately 1,600 miles of natural gas gathering pipelines in western Pennsylvania, western New York and eastern Ohio.

On June 15, 2006, the Company's Board of Directors approved the change of its year end to December 31 from September 30. On July 24, 2006, the Company filed a transition report on Form 10-Q for the quarter ended December 31, 2005 pursuant to Rule 13a-10 of the Securities and Exchange Commission for transition period reporting. Accordingly, the Company's consolidated financial statements reflect its new year end of December 31 for the year ended December 31, 2006. Additionally, financial statements for the three months ended December 31, 2005 and the years ended September 30, 2005 and 2004.

NOTE 1 – NATURE OF OPERATIONS - (Continued)

On February 6, 2006, the Company's Board of Directors approved a three-for-two stock split effected in the form of a 50% stock dividend. Shareholders of record as of February 28, 2006, received one additional share of common stock for each two shares of common stock they owned on that date. The shares were distributed on March 10, 2006. After the split, there were approximately 20.0 million shares of the Company's common stock outstanding and the adjusted per-share stock price was reported by the NASDAQ Stock Market, effective March 13, 2006.

Spin-off from Resource America, Inc.

On June 30, 2005, RAI distributed its remaining 10.7 million shares of the Company to its stockholders in the form of a tax-free dividend. Each stockholder of RAI received 0.59367 shares of the Company for each share of RAI common stock owned as of June 24, 2005, the record date. Although the distribution itself is tax-free to RAI stockholders, as a result of the deconsolidation there may be some tax liability arising from prior unrelated corporate transactions among the Company and some of its subsidiaries. The Company anticipates that all or a portion of any liability arising from this transaction may be reimbursed by us to RAI. The Company no longer consolidated with RAI as of June 30, 2005. In connection with the spin-off, RAI and Company entered into a series of agreements. There are two agreements that govern the ongoing relationship between the Company and RAI that are still in effect at December 31, 2006. These agreements are the tax matters agreement and the transition services agreement.

The tax matters agreement governs the respective rights, responsibilities and obligations of the Company and RAI with respect to tax liabilities and benefits, tax attributes, tax contests and other matters regarding income taxes, non-income taxes and related tax returns.

The transition services agreement governs the provision of support services by the Company to RAI and by RAI to the Company, such as:

- cash management and debt service administration;
- accounting and tax;
- investor relations;
- payroll and human resources administration;
- legal;
- information technology;
- data processing;
- real estate management; and
- other general administrative functions.

We and RAI pay each other a fee for these services. The fee is payable monthly in arrears, 15 days after the close of the month. We and RAI also agreed to pay or reimburse each other for any out-of-pocket payments, costs and expenses associated with these services.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly-owned except for Atlas Pipeline Holdings and Atlas Energy Resources. In accordance with established practice in the oil and gas industry, the Company's financial statements include its pro-rata share of assets, liabilities, revenues, and costs and expenses of the energy partnerships in which the Company has an interest. All material intercompany transactions have been eliminated.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

Use of Estimates

Preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and costs and expenses during the reporting period. Actual results could differ from these estimates.

Reclassifications

Certain reclassifications have been made to the prior period consolidated financial statements to conform to the 2006 presentation.

Stock-Based Compensation

The Company has adopted SFAS No. 123(R), “Share-Based Payment,” as revised (“SFAS No. 123(R)”), as of October 1, 2005 using the modified prospective method. 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. 123R, the Company applied the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees (“APB No. 25”), and related interpretations, including the Company’s participation of its employees’ in RAI’s stock option plans prior to its spin-off from RAI. Under this method compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeds the exercise price.

Under SFAS 123R, the fair value of stock-based awards to employees is calculated through the use of option pricing models, even though such models were developed to estimate the fair value of freely tradable, fully transferable options without vesting restrictions, which significantly differ from RAI’s stock option awards. These models also require subjective assumptions, including future stock price volatility and expected time to exercise, which greatly affect the calculated values.

Prior to October 1, 2005, no stock-based employee compensation cost was reflected in the Company’s net income, as all options granted under both the plans in which the Company’s employees participate (see Note 9) had an exercise price equal to the market value of the underlying common stock on the date of grant. The vesting of all unvested options under the RAI was accelerated for all Company employees and all options were subsequently exercised prior to June 30, 2005 in anticipation of the spin-off from RAI. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation (in thousands, except share data).

	Years Ended September 30,	
	2005	2004
Net income, as reported	$32,940	$21,187
Less total stock-based employee compensation expense determined under the fair value based method for all awards, net of income taxes	(7,283)	(378)
Pro forma net income	$25,657	$20,809
Earnings per share:		
Basic-as reported	$ 1.65	$ 1.21
Basic-pro forma	$ 1.28	$ 1.19
Earnings per share:		
Diluted-as reported	$ 1.64	$ 1.21
Diluted-pro forma	$ 1.28	$ 1.19

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

The pro forma net income in 2005 above includes $6.7 million in expense (net of taxes) related to options for 500,000 shares issued in 2005 which were immediately exercisable. The Company issued these options under these terms to avoid a substantial charge to earnings upon adoption of FASB Statement No 123(R).

Earnings Per Share

Basic earnings per share are determined by dividing net income by the weighted average number of shares of common stock outstanding during the period. Earnings per share - diluted is computed by dividing net income by the sum of the weighted average number of shares of common stock outstanding and dilutive potential shares issuable from the exercise of stock options and award plans. Dilutive potential shares of common stock consist of the excess of shares issuable under the terms of various stock option agreements over the number of such shares that could have been reacquired (at the weighted average price of shares during the period) with the proceeds received from the exercise of the options.

The components of basic and diluted earnings per share for the periods indicated are as follows:

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30,	
			2005	2004
		(in thousands)		
Income from continuing operations	$ 12,176	$ 11,724	$ 32,940	$ 21,187
Cumulative effect of accounting change, net of taxes	3,825	—	—	—
Net income	$ 16,001	$ 11,724	$ 32,940	$ 21,187
Weighted average common shares outstanding—basic	19,716	20,003	20,001	17,525
Dilutive effect of stock option and award plans	441	210	48	1
Weighted average common shares—diluted	20,157	20,213	20,049	17,526

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" and for the Company include changes in the fair value, net of taxes, of unrealized hedging gains and losses and changes in post retirement plan liabilities.

Receivables

In evaluating its allowance for possible losses, the Company 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 Company's review of its customer's credit information. The Company extends credit on an unsecured basis to many of its energy customers. At December 31, 2006, the Company's credit evaluation indicated that it has no need for an allowance for possible losses.

Property and Equipment

Property and equipment is stated at cost. Depreciation, depletion and amortization is based on cost less estimated salvage value primarily using the unit-of-production or straight line method over the assets estimated useful lives. Maintenance and repairs are expensed as incurred. Major renewals and improvements that extend the useful lives of property are capitalized.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

The estimated service lives of property and equipment are as follows:

Pipelines, processing and compression facilities	15 – 35 years
Rights-of-way – Mid-Continent	40 years
Rights-of-way – Appalachia	20 years
Land, buildings and improvements	10 – 40 years
Furniture and equipment	3 – 7 years
Other	3 – 10 years

Property and equipment consists of the following at the dates indicated:

	December 31, 2006	December 31, 2005
	(in thousands)	
Mineral interests:		
Proved properties	$ 1,290	$ 2,308
Unproved properties	1,002	1,002
Wells and related equipment	348,592	273,725
Pipelines, processing and compression facilities	611,212	445,859
Rights-of-way	30,401	15,769
Land, building and improvements	8,451	7,799
Support equipment	5,604	4,201
Other	9,902	6,292
	1,016,454	756,955
Accumulated depreciation, depletion and amortization:		
Oil and gas properties and pipelines	(125,550)	(94,105)
Other	(6,092)	(4,503)
	(131,642)	(98,608)
	$ 884,812	$ 658,347

In October 2005, Atlas Pipeline completed the acquisition of 75% interest in NOARK Pipeline System, Limited Partnership (“NOARK”) for approximately $179.8 million (see Note 12). On May 2, 2006 Atlas Pipeline acquired the remaining 25% interest in NOARK for $69.0 million in cash, including the repayment of the $39 million NOARK notes at the date of the acquisition (see Note 12). During 2006, based on the findings of an independent valuation firm, Atlas Pipeline adjusted the preliminary purchase price allocation for the NOARK acquisition and reallocated the preliminary amounts from goodwill to customer contracts and relations intangible assets and to property, plant and equipment. The purchase price allocation is based on estimated values, which are subject to adjustment.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil is converted to gas equivalent basis (“mcfe”) at the rate one barrel equals 6 mcf. Depletion is provided on the units-of-production method. Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable and impaired if conditions indicate the Company will not explore the acreage prior to expiration or the carrying value is above fair value.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

The Company's long-lived assets are reviewed for impairment annually for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization and asset retirement obligations is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company's plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. If the carrying value exceeds such cash flows, an impairment loss is recognized for the difference between the estimated fair market value, (as determined by discounted future cash flows) and the carrying value of the assets.

Upon the sale or retirement of a complete or partial unit of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to accumulated depletion. Upon the sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the statements of income. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

Asset Retirement Obligations

The Company accounts for asset retirement obligations as required under FAS No. 143, *Accounting for Retirement Asset Obligations* ("SFAS 143"). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. The Company has asset retirement obligations related to the plugging and abandonment of its oil and gas wells. SFAS 143 requires the Company to consider estimated salvage value in the calculation of depreciation, depletion and amortization.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarified that the term "conditional asset retirement obligation" as used in FAS No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset obligation should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of a conditional asset retirement obligation under FAS No. 143.

Under FASB No.143, the Company had recorded its asset retirement obligation based on a probability factor which considered the Company's history of selling its wells or otherwise disposing of them without incurring a disposal expense. FIN 47 requires the Company to record its retirement obligation without regard to its prior practice and accrue for obligations for all wells owned by the Company without regard to their probability of being sold or otherwise disposed of without incurring a disposal expense.

Accordingly, the Company adopted FIN 47 as of December 31, 2006 and recognized $3.8 million (net of tax of $2.6 million) in 2006 as the cumulative effect of an accounting change. Additionally, the Company's balance sheet recognized an increase as of December 31, 2006 in its asset retirement obligation of $8.0 million, and a net increase in property and equipment of approximately $14.4 million.

Had the Company implemented FIN 47 retroactively to October 1, 2002, the following pro forma information summarizes the impact for the periods presented (in thousands):

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004
Net income as reported	$ 16,001	$ 11,724	$ 32,940	$ 21,187
Proforma asset retirement obligation income	851	346	948	805
Proforma net income	$ 16,852	$ 12,070	$ 33,888	$ 21,992
Proforma asset retirement obligation	$ 26,726	$ 26,086	$ 25,126	$ 11,357

Fair Value of Financial Instruments

The Company used the following methods and assumptions in estimating the fair value of each class of financial instrument for which it is practicable to estimate fair value.

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments.

For derivatives the carrying value approximates fair value because the Company marks to market all derivatives.

For secured revolving credit facilities and all other debt, the carrying value approximates fair value because of the short term maturity of these instruments and the variable interest rates in the debt agreements.

Derivative Instruments

The Company applies the provisions of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“SFAS 133”). SFAS 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 earnings unless specific hedge accounting criteria are met.

Concentration of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist principally of periodic temporary investments of cash and cash equivalents. The Company places its temporary cash investments in high-quality short-term money market instruments and deposits with high-quality financial institutions and brokerage firms. At December 31, 2006, the Company had $190.9 million in deposits at various banks, of which $189.4 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company 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 Company maintains insurance which may cover in whole or in part certain environmental expenditures. For the three years ended December 31, 2006, the Company had no environmental matters requiring specific disclosure or requiring recording of a liability.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

Revenue Recognition

The Company conducts certain energy activities through, and a portion of its revenues are attributable to, sponsored energy limited partnerships. The Company contracts with the energy partnerships to drill partnership wells. The contracts require that the energy partnerships must pay the Company the full contract price upon execution. The income from a drilling contract is recognized as the services are performed using the percentage of completion method. The contracts are typically completed in less than 60 days. On an uncompleted contract, the Company classifies the difference between the contract payments it has received and the revenue earned as a current liability.

The Company recognizes gathering, transmission and processing revenues at the time the natural gas and liquids are delivered.

The Company recognizes well services revenues at the time the services are performed.

The Company is entitled to receive management fees according to the respective partnership agreements. The Company recognizes such fees as income when earned and includes them in well services revenues.

The Company records the income from the working interests and overriding royalties of wells in which it owns an interest when the gas and oil are delivered.

Because there are timing differences between the delivery of natural gas, NGLs and oil and the Company's receipt of a delivery statement, the Company has unbilled revenues. These revenues are accrued based upon volumetric data from the Company's records and the Company's estimates of the related transportation and compression fees which are, in turn, based upon applicable product prices. The Company had unbilled trade receivables at December 31, 2006 and 2005 of $40.2 million and $71.6 million, respectively, which are included in Accounts Receivable on its Consolidated Balance Sheets.

Supplemental Cash Flow Information

The Company considers temporary investments with a maturity at the date of acquisition of 90 days or less to be cash equivalents.

Supplemental disclosure of cash flow information (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Cash paid for:				
Interest	$ 26,800	$ 3,458	$ 8,807	$ 2,114
Income taxes paid (refunded)	57,670	4,957	23	(220)
Non-cash investing activities include the following:				
Fair value of assets acquired	$ 28,575	$ 231,959	$ 199,833	$160,799
Liabilities	$ 1,425	$ (52,114)	$ (4,571)	$(19,235)
Cash Acquired	$ 0	$ (16,215)	$ 0	$ 0
Net cash paid	$ 30,000	$ 163,630	$ 195,262	$141,564

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

Income Taxes

The Company records deferred tax assets and liabilities, as appropriate, to account for the estimated future tax effects attributable to temporary differences between the financial statement and tax bases of assets and liabilities and operating loss carryforwards, using currently enacted tax rates. The deferred tax provision or benefit each year represents the net change during that year in the deferred tax asset and liability balances. Separate company state tax returns are filed in those states in which the Company is registered to do business.

Recently Issued Financial Accounting Standards

In February 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards 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 the Company has not made any decisions in its application and is evaluating the impact of the adoption of SFAS 159 on the Company's financial position and results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employer's Accounting for Defined Benefit Pension and Other Post Retirement Plans* ("SFAS 158"). SFAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan as an asset or liability, by recording the difference between the plan assets fair value and the benefit obligation. The employer must recognize after-tax gains and losses as a result of changes in the funded status as a component of other comprehensive income. The employer is also required to measure the funded status of a plan as of the date of its year end statements, and disclose in the notes to the statements additional information regarding the net periodic benefit costs. SFAS 158 is effective for the Company for the year ended December 31, 2006. The adoption of SFAS 158 did not have a significant impact on the Company's financial position or results of operations (see Note 9).

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS 157"). SFAS 157 addresses the need for increased consistency in fair value measurements, defining fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It also establishes a framework for measuring fair value and expands disclosure requirements. SFAS 157 is effective for the Company beginning January 1, 2008. The Company is currently evaluating the impact of its adoption of SFAS 157 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 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. SAB 108 is effective for fiscal years ending on or after November 15, 2006.

Traditionally, there have been two widely-recognized methods for quantifying the effects of financial statement misstatements: the "roll-over" method and the "iron curtain" method. The roll-over method focuses primarily on the impact of a misstatement on the income statement, including the reversing effect of prior year misstatements, but its use can lead to the accumulation of misstatements in the balance sheet. The iron-curtain method, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. Prior to the Company's application of the guidance in SAB 108, the Company used the roll-over method for quantifying identified financial statement misstatements and concluded that they were immaterial individually and in the aggregate.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (Continued)

With SAB 108, the SEC staff established an approach that requires quantification of financial statement misstatements based on the effects of the misstatements on each of the company's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it requires quantification of errors under both the iron curtain and the roll-over methods.

SAB 108 permits existing public companies to initially apply its provisions either by (i) restating prior financial statements as if the "dual approach" had always been applied or (ii) recording the cumulative effect of initially applying the "dual approach" as adjustments to the carrying values of assets and liabilities as of the beginning of a Company's fiscal year, with an offsetting adjustment recorded to the opening balance of retained earnings. The Company elected to record the effects of applying SAB 108 using the cumulative effect transition method to its accounting practice for recording incentive compensation for its executive officers and other employees which it historically recognized in the year in which it was paid. Concurrent with the Company's change in year-end from September 30 to December 31, the Company adopted the provisions of SAB 108, and recorded an increase in accrued liabilities in the amount of $4.0 million, a decrease in accrued income taxes of $1.6 million and a reduction of retained earnings of approximately $2.4 million as of January 1, 2006.

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements and provides guidance on the recognition, de-recognition and measurement of benefits related to an entity's uncertain tax positions. FIN 48 is effective for the Company beginning January 1, 2007. The Company does not expect the adoption of FIN 48 to have a significant impact on its financial position or results of operations.

NOTE 3 — OTHER ASSETS, INTANGIBLE ASSETS AND GOODWILL

Other Assets

The following table provides information about other assets at the dates indicated (in thousands):

	December 31, 2006	December 31, 2005
Deferred financing costs, net of accumulated amortization of $6,862 and $3,044	$ 13,040	$ 15,654
Investments	1,553	1,647
Security deposits	1,538	1,725
Long-term hedge receivable from Partnerships	2,131	9,340
Long-term hedge receivable	24,148	4,387
Other	91	79
	$ 42,501	$ 32,832

Deferred financing costs are recorded at cost and are amortized over the terms of the related loan agreements which range from three to ten years. Long-term hedge receivable from Partnerships represents amounts due from Atlas Energy's affiliated partnerships for unrealized long-term holding losses from hedging activities allocated to them.

Intangible Assets

Customer contracts and relationships. At December 31, 2006, Atlas Pipeline had $25.5 million of intangible assets, net of accumulated amortization of $4.1 million which was recorded in connection with natural gas gathering contracts and customer relationships assumed in its acquisition of Elk City (see Note 12). Statement of Financial Accounting Standard No. 142, *Goodwill and Other Intangible Assets* ("SFAS 142"), requires that intangible assets such as these gas gathering contracts and customer relations with finite useful lives be amortized over their respective 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 shall be amortized

NOTE 3 — OTHER ASSETS, INTANGIBLE ASSETS AND GOODWILL – (Continued)

over the best estimate of its useful life. At a minimum, Atlas Pipeline will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. During 2006, Atlas Pipeline adjusted the preliminary purchase price allocation for NOARK and eliminated the previously estimated allocated value of customer contracts and customer relationships related to this acquisition based upon a preliminary finding by an independent valuation firm. Amortization expense on the customer contract and relationships intangible assets related to Elk City, which have estimated lives of eight and twenty years, respectively, and are being amortized on a straight-line basis, was $2.0 million, $1.6 million, $492,000 and $0 for the year December, 2006, three months ended December 31, 2005 and years ended September 30, 2005 and 2004, respectively.

Partnership management and operating contracts. Included in intangible assets are partnership management and operating contracts acquired through acquisitions which are recorded at fair value on their acquisition dates. The Company amortizes contracts acquired on the declining balance and straight-line methods, over their respective estimated lives, ranging from five to thirteen years. Amortization expense for these contracts for the years ended December 31, 2006, three months ended December 31, 2005, and years ended September 30, 2005 and 2004 was $878,800, $220,000, $933,000 and $1.0 million, respectively.

Aggregate estimated annual amortization expense for all of the contracts described above for the next five periods ending December 31 is as follows: 2007-$3.2 million; 2008-$3.2 million; 2009-$3.2 million; 2010-$3.1 million and 2011-$3.1 million.

The following table provides information about intangible assets at the dates indicated:

	December 31, 2006 (in thousands)		December 31, 2005 (in thousands)	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Customer contracts and relations	$ 29,650	$ (4,120)	$ 56,950	$ (2,081)
Partnership management and operating contracts	14,343	(9,132)	14,343	(8,253)
Intangible assets, net	$ 43,993	$ (13,252)	$ 71,293	$ (10,334)

Goodwill

The Company applies the provisions of SFAS No. 142 which requires that goodwill no longer be amortized, but instead evaluated for impairment at least annually. The evaluation of impairment under SFAS 142 requires the use of projections, estimates and assumptions as to the future performance of the Company'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 Company's assumptions and, if required, recognition of an impairment loss. The Company's evaluation of goodwill at December 31, 2006 (the most recent valuation date) indicated there was no impairment loss and no impairment indicators have arisen since that date. The Company will continue to evaluate its goodwill at least annually or when impairment indicators arise, and will reflect the impairment of goodwill, if any, within the consolidated statements of income in the period in which the impairment is indicated. A reconciliation of the Company's goodwill for the periods indicated is as follows (in thousands).

	December 31 2006	December 31, 2005
Goodwill at beginning of period, net of accumulated amortization of $4,532	$ 146,544	$ 115,366
Adjustment to goodwill related to Atlas Pipeline acquisitions (see Note 12)	(47,937)	31,178
Goodwill at end of period, net of accumulated amortization of $4,532	$ 98,607	$ 146,544

NOTE 4 – ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No 143 *Accounting for Asset Retirement Obligations* ("SFAS 143") and FASB Interpretation No. 47 *Accounting for Conditional Asset Retirement Obligations*, which require the Company to recognize an estimated liability for the plugging and abandonment of its oil and gas wells. Under SFAS 143, the Company must currently recognize a liability for future asset retirement obligations if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS 143 requires the Company to consider estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The increase in asset retirement obligations in 2005 was due to an upward revision in the estimated cost of plugging and abandoning wells.

The Company has no assets legally restricted for purposes of settling asset retirement obligations. Except for the item previously referenced, the Company has determined that there are no other material retirement obligations associated with tangible long-lived assets.

A reconciliation of the Company's liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	2004
Asset retirement obligations, beginning of year	$ 18,499	$ 17,651	$ 4,888	$ 3,131
Cumulative effect of adoption of FIN 47	8,042	—	—	—
Liabilities incurred	1,570	725	770	1,724
Liabilities settled	(194)	—	(137)	(58)
Revision in estimates	(2,411)	—	11,789	(205)
Accretion expense	1,220	123	341	296
Asset retirement obligations, end of year	$ 26,726	$ 18,499	$ 17,651	$ 4,888

The above accretion expense is included in depreciation, depletion and amortization in the Company's consolidated statements of income and the asset retirement obligation liabilities are included in other liabilities in the Company's consolidated balance sheets.

NOTE 5 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In the ordinary course of its business operations, the Company has ongoing relationships with several related entities:

Relationship with Company Sponsored Partnerships. The Company conducts certain activities through, and a substantial portion of its revenues are attributable to, energy limited partnerships ("Partnerships"). The Company serves as general partner of the Partnerships and assumes customary rights and obligations for the Partnerships. As the general partner, the Company is liable for Partnership liabilities and can be liable to limited partners if it breaches its responsibilities with respect to the operations of the Partnerships. The Company is entitled to receive management fees, reimbursement for administrative costs incurred, and to share in the Partnerships' revenue, and costs and expenses according to the respective Partnership agreements.

Relationship with RAI. On June 30, 2005, RAI completed its spin-off of the Company. The Company reimburses RAI for various costs and expenses it incurs on behalf of the Company, primarily payroll and rent. For the year ended December 31, 2006, three months ended December 31, 2005, and the years ended September 30, 2005 and 2004, these costs totaled $1.2 million, $163,000, $602,000 and $1.1 million, respectively.

NOTE 5 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS – (Continued)

RAI's relationship with Anthem Securities (a wholly-owned subsidiary of the Company). Anthem Securities is a wholly-owned subsidiary of the Company and a registered broker-dealer which serves as the dealer-manager of investment programs sponsored by RAI's real estate and equipment finance segments. Some of the personnel performing services for Anthem have been paid by RAI, and Anthem reimburses RAI for the allocable costs of such personnel. In addition, RAI has agreed to cover some of the operating costs for Anthem's office of supervisory jurisdiction, principally licensing fees and costs. RAI paid $1.3 million, $111,000, $270,000, and $7,000, toward such operating costs of Anthem for the year ended December 31, 2006, three months ended December 31, 2005 and the years ended September 30, 2005 and 2004, respectively. During the same periods, Anthem reimbursed RAI $2.7 million, $442,000, $653,000 and $156,000, respectively, for costs incurred on Anthem's behalf.

As of December 31, 2006 and 2005, certain operating expenditures totaling $117,000 and ($492,000), respectively that remain to be settled between the Company and RAI are reflected in the Company's consolidated balance sheets as advances to/from affiliate.

NOTE 6 — DERIVATIVE INSTRUMENTS

Atlas Energy Resources. From time to time, Atlas Energy enters into natural gas futures and option contracts to hedge its exposure to changes in natural gas prices. At any point in time, such contracts may include regulated New York Mercantile Exchange ("NYMEX") futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas.

Atlas Energy formally documents all relationships between hedging instruments and the items being hedged, including the risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. Atlas Energy assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives are highly effective in offsetting changes in the fair value of hedged items. Historically these contracts have qualified and been designated as cash flow hedges and recorded at their fair values. Gains or losses on future contracts are determined as the difference between the contract price and a reference price, generally prices on NYMEX. Such gains and losses are charged or credited to Accumulated Other Comprehensive Income (Loss) and recognized as a component of sales revenue in the month the hedged gas is sold. If it is determined that a derivative is not highly effective as a hedge or it has ceased to be a highly effective hedge, due to the loss of correlation between changes in gas reference prices under a hedging instrument and actual gas prices, Atlas Energy will discontinue hedge accounting for the derivative and subsequent changes in fair value for the derivative will be recognized immediately into earnings.

A portion of Atlas Energy's future natural gas 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.

At December 31, 2006, Atlas Energy had 234 open natural gas futures contracts related to natural gas sales covering 54.9 million MMBtus of natural gas, maturing through December 31, 2010 at a combined average settlement price of $8.48 per MMBtu. Atlas Energy recognized a gain of $7.1 million on settled contracts covering natural gas production for the year ended December 31, 2006. There were no gains or losses recognized during the year ended December 31, 2006 for hedge ineffectiveness or as a result of the discontinuance of these cash flow hedges. There were no gains or losses recognized on hedging in the three months ended December 31, 2005 and the years ended September 30, 2005 and 2004. Of the $47.5 million net unrealized hedge gain at December 31, 2006, our portion is $21.1 million and $26.4 million has been reallocated to the investment partnerships.

Atlas Pipeline. Atlas Pipeline also enters into certain financial swaps and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activity* 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, Atlas Pipeline receives a fixed price and remits a floating price based on certain indices for the relevant contract period.

NOTE 6 — DERIVATIVE INSTRUMENTS – (Continued)

Atlas Pipeline 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 natural gas futures and options contracts to the forecasted transactions. Atlas Pipeline 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, Atlas Pipeline will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined through the utilization of market data, will be recognized immediately within its consolidated statements of income.

A portion of Atlas Pipeline's future natural gas 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.

Derivatives are recorded on Atlas Pipeline's balance sheet as assets or liabilities at fair value. At December 31, 2006, Atlas Pipeline had a net hedging liability of $20.1 million. Ineffective hedge gains or losses are recorded in Atlas Pipeline's consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. Atlas Pipeline recognized losses of $13.9 million, $5.6 million, $5.0 million, and $27,000 for the year ended December 31, 2006, three months ended December 31, 2005 and year ended September 30, 2005 and 2004, respectively, related to the settlement of qualifying hedge instruments. Atlas Pipeline also recognized a gain of $5.7 million and losses of $320,000, $64,000, and $697,000 for the years ended December 31, 2006, three months ended December 31, 2005 and year ended September 30, 2005 and 2004, respectively, related to the change in market value of non-qualifying or ineffective hedges. Such gains and losses are included within transmission, gathering and processing in the Company's consolidated statements of income.

At December 31, 2006 and December 31, 2005, the Company reflected a net hedging asset and liability on its balance sheets of $27.3 million and $41.5 million, respectively, when combining the above hedges of Atlas Energy and Atlas Pipeline. Of the $8.8 million net gain in accumulated other comprehensive income at December 31, 2006, the Company will reclassify $5.2 million of gains to its consolidated statements of income over the next twelve month period as these contracts expire, and $3.6 million of gains will be reclassified in later periods if the fair values of the instruments remain at current market values. Actual amounts that will be reclassified will vary as a result of future price changes.

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

ATLAS ENERGY RESOURCES HEDGES

Fixed Price Swaps

Twelve Month Period Ending December 31	Volumes	Average Fixed Price	Fair Value Asset
	(MMBTU)[1]	(per MMBTU)	(in thousands) [3]
2007	14,650,000	$ 8.59	$ 25,935
2008	15,800,000	8.91	11,450
2009	15,720,000	8.30	7,690
2010	5,400,000	7.53	587
			$ 45,662

NOTE 6 — DERIVATIVE INSTRUMENTS – (Continued)

Costless Collars

Twelve Month Period Ending December 31	Option Type	Volumes	Average Floor and Cap	Fair Value Asset
		(MMBTU)[1]	(per MMBTU)	(in thousands) [3]
2007	Puts purchased	1,800,000	$ 7.50 – 8.60	$ 1,511
2007	Calls sold	1,800,000	$ 7.50 – 8.60	—
2008	Puts purchased	1,560,000	$ 7.50 – 9.40	281
2008	Calls sold	1,560,000	$ 7.50 – 9.40	—
				$ 1,792

ATLAS PIPELINE HEDGES

Natural Gas Fixed – Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Asset/(Liability)[2]
	(gallons)	(per gallon)	(in thousands)
2007	84,924,000	0.85	3,058
2008	33,012,000	0.70	(3,996)
2009	8,568,000	0.75	(795)
			$ (1,733)

Natural Gas Fixed – Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Asset/(Liability)[3]
	(MMBTU)[1]	(per MMBTU)	(in thousands)
2007	1,080,000	$ 7.26	$ 313
2008	240,000	7.27	(216)
2009	480,000	8.00	78
			$ 175

Natural Gas Basis Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Asset[3]
	(MMBTU)[1]	(per MMBTU)	(in thousands)
2007	1,080,000	$ (0.53)	$ 420
2008	240,000	(0.55)	150
2009	480,000	(0.54)	41
			$ 611

NOTE 6 — DERIVATIVE INSTRUMENTS – (Continued)

Natural Gas Fixed Price (Purchase)

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability(3)
	(MMBTU)(1)	(per MMBTU)	(in thousands)
2007	6,960,000	$ 8.85	$ (15,374)
2008	3,336,000	8.87	(3,442)
2009	2,400,000	8.45	(1,470)
			$ (20,286)

Natural Gas Basis (Purchase)

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability(3)
	(MMBTU)(1)	(per MMBTU)	(in thousands)
2007	6,960,000	$ (0.90)	$ (54)
2008	3,336,000	(1.04)	(63)
2009	2,400,000	(0.60)	(59)
			$ (176)

Crude Oil Fixed – Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability(3)
	(barrels)	(per barrel)	(in thousands)
2007	77,900	$ 56.17	$ (670)
2008	65,400	59.42	(526)
2009	33,000	62.70	(148)
			$ (1,344)

Crude Oil Options

Production Period Ended December 31,	Option Type	Volumes	Average Strike Price	Fair Value Asset/ (Liability)(3)
		(barrels)	(per barrel)	(in thousands)
2007	Puts purchased	13,200	$ 60.00	$ 33
2007	Calls sold	13,200	73.38	$ (26)
2008	Puts purchased	17,400	60.00	$ 71
2008	Calls sold	17,400	72.78	$ (85)
2009	Puts purchased	30,000	60.00	$ 147
2009	Calls sold	30,000	71.25	$ (178)
				$ (38)

NOTE 6 — DERIVATIVE INSTRUMENTS – (Continued)

Crude Oil Sales Options (NGL)

Production Period Ended December 31,	Option Type	Volumes	Average Strike Price	Fair Value Asset/ (Liability)(3)
		(barrels)	(per barrel)	(in thousands)
2008	Puts purchased	720,000	$ 60.00	$ 2,919
2008	Calls sold	720,000	84.00	$ (1,508)
2009	Puts purchased	720,000	60.00	$ 3,527
2009	Calls sold	720,000	81.00	$ (2,272)
				$ 2,666
	Total net asset			$ 27,329

(1) MMBTU represents million British Thermal Units.

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

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

(4) Includes Atlas Pipeline'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 Atlas Pipeline'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.

The following table sets forth the book and estimated fair values of derivative instruments at the dates indicated (in thousands):

	December 31, 2006		December 31, 2005	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Derivative instruments	$ 57,203	$ 57,203	$ 18,965	$ 18,965
	$ 57,203	$ 57,203	$ 18,965	$ 18,965
Liabilities				
Derivative instruments	$ (29,874)	$ (29,874)	$ (60,473)	$ (60,473)
	$ (29,874)	$ (29,874)	$ (60,473)	$ (60,473)
	$ 27,329	$ 27,329	$ (41,508)	$ (41,508)

NOTE 7 – DEBT

Total debt consists of the following at the dates indicated (in thousands):

	December 31, 2006	December 31, 2005
Senior notes – Atlas Pipeline	$ 285,977	$ 250,000
Revolving credit facility – Atlas Pipeline	38,000	9,500
Installment notes – NOARK	—	39,000
Other debt	174	281
	324,151	298,781
Less current maturities	109	1,351
	$ 324,042	$ 297,430

Atlas Pipeline Credit Facility. Atlas Pipeline has a $225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears interest, at Atlas Pipeline's option, at either (i) adjusted London Interbank Offered Rate ("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 Company's consolidated balance sheets. Borrowings under the credit facility are secured by a lien on and security interest in all of Atlas Pipeline's property and that of its subsidiaries, and by the guaranty of each of its subsidiaries. The credit facility contains customary covenants, including restrictions on Atlas Pipeline's ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; and enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. Atlas Pipeline is 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 Atlas Pipeline in excess of a specified amount and a change of control of the general partner.

Senior Notes. In December 2005, Atlas Pipeline, 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, Atlas Pipeline 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 $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 unpaid interest to the date of redemption. In addition, prior to December 15, 2008, Atlas Pipeline 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 Atlas Pipeline 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 for which the net proceeds are not reinvested into Atlas Pipeline within 360 days. The Senior Notes are junior in right of payment to Atlas Pipeline's secured debt, including Atlas Pipeline's obligations under its credit facility.

The indenture governing the Senior Notes contains covenants, including limitations of Atlas Pipeline'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. Atlas Pipeline is in compliance with these covenants as of December 31, 2006.

NOTE 7 – DEBT - (Continued)

In connection with a Senior Notes registration rights agreement entered into by Atlas Pipeline, 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 Atlas Pipeline had not met the aforementioned deadlines, the Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that the deadlines had been met. On April 19, 2006, Atlas Pipeline 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.

Atlas Pipeline Holdings Credit Facility. On July 26, 2006, Atlas Pipeline Holding, L.P. ("AHD"), as borrower, and Atlas Pipeline GP, as guarantor, entered into a $50.0 million revolving credit facility (-0- outstanding at December 31, 2006) with Wachovia Bank, National Association, as administrative agent and issuing bank, and a syndicate of banks. AHD's credit facility matures in April 2010 and bears interest, at its option, at either (i) adjusted LIBOR (as defined in the credit facility) or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank, National Association prime rate, except that no more than five LIBOR loans may be outstanding at any time. Borrowings under the credit facility are secured by a first-priority lien on a security interest in all of the AHD's assets, including a pledge of Atlas Pipeline GP's interests in Atlas Pipeline, and are guaranteed by Atlas Pipeline GP and AHD's other subsidiaries (excluding Atlas Pipeline and its subsidiaries). The credit facility contains customary covenants, including restrictions on its ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to AHD's unitholders if an event of default exists or would result from such distribution; or enter into a merger or sale of substantially all of AHD's property or assets, including the sale or transfer of interests in its subsidiaries. AHD is in compliance with these covenants as of December 31, 2006.

Atlas Energy Resources, LLC Credit Facility. In December 2006, Atlas Energy entered into a new credit facility, which is led by Wachovia Bank, N.A. ("Wachovia"), to a maximum of $250.0 million. The revolving credit facility has a current borrowing base of $155.0 million which may be redetermined subject to changes in Atlas Energy's oil and gas reserves. Up to $50.0 million of the facility may be in the form of standby letters of credit. The facility is secured by Atlas Energy's assets and bears interest at either the base rate plus the applicable margin or at adjusted LIBOR plus the applicable margin, elected at Atlas Energy's option.

The base rate for any day equals the higher of the federal funds rate plus 0.50% or the Wachovia prime rate. Adjusted LIBOR is LIBOR divided by 1.00 minus the percentage prescribed by the Federal Reserve Board for determining the reserve requirement for Euro currency funding. The applicable margin ranges from 0.0% to 0.75% for base rate loans and 1.00% to 1.75% for LIBOR loans.

The Wachovia credit facility requires Atlas Energy to maintain specified ratios of current assets to current liabilities, interest coverage (as defined), and debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA"). In addition, the facility limits sales, leases or transfers of assets and the incurrence of additional indebtedness. The facility limits the dividends payable by Atlas Energy if an event of default has occurred and is continuing or would occur as a result of such distribution. Atlas Energy is in compliance with these covenants as of December 31, 2006. The facility terminates in December 2011, when all outstanding borrowings must be repaid. At December 31, 2006 and December 31, 2005, $.5 million and $16.5 million, respectively, were outstanding under this facility under letters of credit which are not reflected as borrowings on the Company's consolidated balance sheet.

Annual debt principal payments over the next five years ending December 31 are as follows (in thousands):

2007	$ 109
2008	65
2009	—
2010	—
2011 and thereafter	323,977
	$ 324,151

NOTE 8 — INCOME TAXES

The following table details the components of the Company's provision for income taxes from continuing operations for the periods indicated:

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
		(in thousands)		
Provision for income taxes:				
Current				
Federal	$ 54,634	$ 5,189	$ 16,913	$ 9,070
State	11,438	664	830	553
Deferred	(8,918)	1,033	2,275	1,786
	$ 57,154 (1)	$ 6,886	$ 20,018	$ 11,409

(1) Includes $29.8 million tax on gain on sale of Atlas Pipeline Holdings, L.P.

A reconciliation between the statutory federal income tax rate and the Company's effective income tax rate is as follows:

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Statutory tax rate	35%	35%	35%	35%
Statutory depletion	(1)	(1)	(2)	(1)
Reorganization costs	—	—	2	—
Other, net	—	—	1	—
State income taxes, net of federal tax benefit	5	3	2	1
Valuation allowance on tax gain on sale of Atlas Pipeline Holdings, L.P.	43	—	—	—
	82%	37%	38%	35%

The components of the Company's net deferred tax liability are as follows:

	December 31, 2006	December 31, 2005
	(in thousands)	
Deferred tax assets related to:		
Unrealized loss on Investments	$ 1,226	$ 3,183
Accrued expenses	2,726	2,230
Investment basis differences	29,846	—
Net operating loss carry forward	192	1,611
Valuation allowance	(30,031)	(243)
Other	885	858
	$ 4,844	$ 7,639
Deferred tax liabilities related to:		
Unrealized gain on Investments	$ (6,658)	$ —
Property and equipment basis differences	(14,954)	(21,529)
Goodwill and other Intangibles	(8,400)	(9,230)
	(30,012)	(30,759)
Net deferred tax liability	$ (25,168)	$ (23,120)

NOTE 8 — INCOME TAXES – (Continued)

Deferred income tax assets and liabilities are classified as current or long-term consistent with the classification of the related temporary difference and are recorded in the Company's consolidated balance sheets as follows:

	December 31,	
	2006	2005
	(in thousands)	
Current deferred tax asset	$ 5,022	$ 6,249
Non-current deferred tax liability	(30,190)	(29,369)
	$ (25,168)	$ (23,120)

The Company had net operating loss carryforwards of $5.9 million at December 31, 2006, primarily related to state income taxes that will expire beginning in 2014 and ending in 2026 if unused. The Company had deferred tax assets of $192,000 for the net operating loss carryforwards and a related valuation allowance of $185,000 at December 31, 2006, all of which was established prior to 2006 based on the uncertainty of generating future taxable income in certain states during the limited period that the net operating loss carryforwards can be carried forward. The Company established an additional valuation allowance of $29.8 million during the year ended December 31, 2006, related to investment basis differences attributable to the initial public offering of Atlas Pipeline Holdings discussed below.

Tax on Gain on Atlas Pipeline Holdings, L.P.

The Company received $74.3 million in proceeds associated with an initial public offering of AHD units on July 26, 2006. Although this transaction did not generate a gain in accordance with generally accepted accounting principles, the distribution of the net proceeds of $74.1 million to the Company generated a taxable gain which resulted in a tax charge of $29.8 million, or $1.51 and $1.48 per share-basic and diluted in the year ended December 31, 2006, which increased the Company's effective tax rate to 82%.

NOTE 9 — BENEFIT PLANS

Stock Incentive Plan. The Company adopted a Stock Incentive Plan (the "Plan") in 2004 which authorized the granting of up to 2.0 million shares of the Company's common stock to employees, affiliates, consultants and directors of the Company in the form of incentive stock options ("ISOs"), non-qualified stock options, stock appreciation rights ("SARs"), restricted stock and deferred units.

Prior to October 1, 2005, the Company accounted for stock-based compensation in accordance with the intrinsic value method as prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB No. 25"). Accordingly, no compensation expense was recognized upon issuance of stock options under the Company's stock incentive plan; however, compensation expense was recognized in connection with the issuance of deferred units granted under the incentive plan.

Adoption of SFAS No. 123R. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"), a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"). SFAS 123R supersedes APB No. 25 and its related implementation guidance, and requires entities to recognize compensation expense for awards of equity instruments to employees based on the grant-date fair value of those awards (with limited exceptions). SFAS No. 123R also requires the benefits of tax deductions in excess of recognized compensation expense to be reported as a financing cash flow, rather than as an operating cash flow as prescribed under the prior accounting rules.

The adoption of SFAS No. 123R at October 1, 2005 primarily resulted in a change in the Company's method of recognizing the fair value of share-based compensation. Specifically, the adoption of SFAS No. 123R resulted in the recording of compensation expense for employee stock options. Results for the year ended September 30, 2005 and 2004 have not been restated. Please see Note 2 (Summary of significant account policies) for the pro forma net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation.

NOTE 9 — BENEFIT PLANS – (Continued)

The Company issues new shares when options are exercised or units are converted to shares. In 2006, the Company received $32,500 from the exercise of options.

Stock Options. In July 2005, options for 1,166,250 shares were issued under the Plan. Options under the Plan become exercisable as to 25% of the optioned shares each year after the date of grant, except options totaling 750,000 shares awarded to Messrs. Edward Cohen and Jonathan Cohen which are immediately exercisable, and expire not later than ten years after the date of grant. The weighted average exercise price of the 750,000 units that vested in the year ended September 30, 2005 was $25.47 per unit. There were no units exercised or forfeited for this period. There were no units granted, vested, exercised or forfeited in the three months ended December 31, 2005. Additional options issued in January and April 2006 also vest over a service period of four years vesting 25% at each anniversary date, expiring ten years from date of grant. Compensation cost is recorded on a graded-vesting schedule. For the year ended December 31, 2006 and three months ended December 31, 2005, the Company recorded compensation expense of $1.3 million and $266,000, respectively for these options. There was no expense recorded in fiscal 2005 and 2004. At December 31, 2006, the Company had unamortized compensation expense of $3.7 million that the Company expects to recognize over four years.

Transactions for stock options issued under the Plan are summarized as follows:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(in Years)	(in Thousands)
Outstanding at December 31, 2005	1,166,250	$ 25.47	9.5	
Granted	65,000	$ 46.68	9.2	
Exercised	(1,275)	$ 25.47	8.6	
Forfeited or expired	(450)	$ 25.47	8.7	
Outstanding at December 31, 2006	1,229,525	$ 26.59	8.5	$ 29,926
Options exercisable at December 31, 2006	852,788	$ 25.47	8.5	$ 21,743
Available for grant	754,348			

The per share weighted average fair value of stock options granted during 2005 was calculated using the binomial (lattice) model with the following weighted average assumptions: (a) expected dividend yield 0%, (b) risk-free interest rate of 5.1%, (c) volatility of 37%, and (d) an expected life of 6.5 years. The per share weighted average fair value of stock options granted in 2006 was calculated using the Black-Scholes-Merton model, with the following assumptions: (a) expected dividend yield 0%, (b) risk-free interest rate on the date of grant, ranging from 4.3% to 4.8%, (c) volatility of 35%, and (d) an expected life of 6.25 years.

Deferred Units. Under the Plan, non-employee directors of the Company are awarded deferred units that vest over a four year period. Each unit represents the right to receive one share of the Company's common stock upon vesting. Units will vest sooner upon a change in control of the Company or death or disability of a grantee, provided the grantee has completed at least six month's service. The fair value of the grants is based on the closing stock price on the grant date, and is being charged to operations over the requisite service periods using a straight-line attribution method. Upon termination of service by a grantee, all unvested units are forfeited. Non-cash compensation expense recognized during the years ended December 31, 2006, three months ended December 2005, and twelve months ended September 2005 and 2004, with respect to these units was $42,500, $6,300, $9,400 and $5,200, respectively. The weighted average grant date fair value of units granted were $0, $20.11 and $10.34 for the three months ended December 31, 2005, and years ended September 30, 2005 and 2004. There were no units that were vested or issued for the three months ended December 31, 2005 and the years ended September 30, 2005 and 2004. Unamortized expense as of December 31, 2006 for deferred stock units is $168,000 and will be recognized over four years.

NOTE 9 — BENEFIT PLANS – (Continued)

The following table summarizes the activity of deferred units for the year ended December 31, 2006:

	Units	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(in Years)	(in Thousands)
Non-vested shares outstanding at December 31, 2005	10,985	$ 13.65	2.8	
Granted	1,916	$ 46.97	3.5	
Vested	(2,415)	$ 10.34	2.0	
Forfeited	—	$ —	—	
Non-vested shares outstanding at December 31, 2006	10,486	$ 20.51	2.4	$ 534

Restricted Units. Restricted units are granted from time to time to employees of the Company. Each unit represents the right to receive one share of the Company's common stock upon vesting. The units are issued to the Restricted Stock Plan when granted, and paid out to the employees on vesting. The units vest one-fourth at each anniversary date over a four year service period. The fair value of the grant is based on the closing price on the grant date, and is being expensed over the requisite service period using a straight line attribution method. Non-cash compensation expense recognized during the year ended December 31, 2006 with respect to these units was $16,000. There were no grants, and no such expense in the three months ended December 31, 2005, or in the twelve months ended September 30, 2005 or 2004. Unamortized expense as of December 31, 2006 for restricted units is $54,000 to be recognized over four years.

The following table summarizes the activity of restricted units for the year ended December 31, 2006:

	Units	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(in Years)	(in Thousands)
Non-vested shares outstanding at December 31, 2005	—	—	—	
Granted	1,500	$ 46.71	3.1	
Vested	—	—	—	
Forfeited	—	—	—	
Non-vested shares outstanding at December 31, 2006	1,500	$ 46.71	3.1	$ 76

Atlas Energy Resources, LLC Long-Term Incentive Plan. In December 2006, Atlas Energy Resources LLC adopted a Long-Term Incentive Plan ("ATN LTIP"), which provides performance incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners.

In 2006, Atlas Energy granted restricted units that vest one fourth at each anniversary over a four year period. Each unit entitles the grantee to one common unit upon vesting, as well as distribution equivalent rights during the period the unit is outstanding. The weighted average remaining contractual term of units that were granted as well outstanding as of December 31, 2006 was 3.3 years. Atlas Energy recognized $188,000 in compensation expense related to restricted units granted pursuant to ATN LTIP for the year ended December 31, 2006. There was no such expense for the three months ended December 31, 2005 or the twelve months ended September 30, 2005 or 2004. At December 31, 2006, Atlas Energy Resources had approximately $812,000 million of unrecognized compensation expense related to the unvested portion of the restricted units to be recognized over four years. The aggregate intrinsic value of units outstanding at December 31, 2006 was $1.1 million. The following table sets forth the ATN LTIP's restricted unit activity for the year ended December 31, 2006:

NOTE 9 — BENEFIT PLANS – (Continued)

	Year Ended December 31, 2006
Outstanding - beginning of period	—
Granted [1]	47,619
Vested	—
Forfeited	—
Outstanding - end of period	47,619

[1] The weighted average fair value for restricted unit awards on the date of grant was $21.00 for awards granted for the year ended December 31, 2006.

Atlas Energy Resources recognized $150,000 in compensation expense related to options granted pursuant to ATN LTIP for the year ended December 31, 2006. There was no such expense for the three months ended December 31, 2005 or the twelve months ended September 30, 2005 or 2004. Unit option awards expire 10 years from the date of grant, and will vest 25% three years from the date of grant and 100% four years from the date of grant. The Black-Scholes option pricing model was used to estimate the weighted average fair value of each unit option granted with the following assumptions (a) expected dividend yield of 8.0%, (b) risk-free interest rate of 4.4%, (c) expected volatility of 25.0%, and (d) an expected life of 6.25 years. At December 31, 2006, Atlas Energy Resources had approximately $650,000 of unrecognized compensation expense related to the unvested portion of the option units to be recognized over four years. The aggregate intrinsic value of stock options outstanding at December 31, 2006 was $624,000. There were no options that vested in 2006. The weighted average remaining contractual term of units that were granted as well as outstanding at December 31, 2006 was 3.3 years. The following table sets forth ATN LTIP's option unit activity for the year ended December 31, 2006:

	Year Ended December 31, 2006	
	Number of unit options	Weighted average exercise price
Outstanding - beginning of period	—	—
Granted [1]	373,752	$ 21.00
Exercised	—	—
Forfeited	—	—
Outstanding - end of period	373,752	$ 21.00

[1] The weighted average remaining contractual life for outstanding options was 9.3 years.

Atlas Pipeline Holdings, L.P. Long-Term Incentive Plan. In November 2006, Atlas Pipeline Holdings adopted a Long-Term Incentive Plan ("AHD LTIP"), which provides performance incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners. The AHD LTIP Committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units.

In 2006 Atlas Pipeline Holdings granted phantom units that vest 25% three years from the grant date and 100% four years from the grant date. Each unit entitles the grantee to one common unit upon vesting, as well as the unit distribution equivalent rights during the period the unit is outstanding. In 2006 the amounts paid with respect to distribution equivalent rights was $37,000. Atlas Pipeline Holdings recognized $229,000 in compensation expense related to phantom units granted pursuant to AHD LTIP for the year ended December 31, 2006. There was no such expense for the three months ended December 31, 2005 or the twelve months ended September 30, 2005 or 2004. At December 31, 2006, Atlas Pipeline Holdings had approximately $4.8 million of unrecognized compensation expense related to the unvested portion of the phantom units to be recognized over four years. The aggregate intrinsic value of units outstanding at December 31, 2006 is $5.3 million. The following table sets forth the AHD LTIP's phantom unit activity for the year ended December 31, 2006. There was no phantom unit activity for the years ended December 31, 2005:

NOTE 9 — BENEFIT PLANS – (Continued)

	Year Ended December 31, 2006
Outstanding - beginning of period	—
Granted [1]	220,492
Vested	—
Forfeited	—
Outstanding - end of period	220,492

[1] The weighted average fair value for phantom unit awards on the date of grant was $22.56 for awards granted for the year ended December 31, 2006.

Atlas Pipeline Holdings recognized $206,000 in compensation expense related to options granted pursuant to AHD LTIP for the year ended December 31, 2006. There was no such expense for the three months ended December 31, 2005 or the twelve months ended September 30, 2005 or 2004. Unit option awards expire 10 years from the date of grant, and will vest 25% three years from the date of grant and 100% four years from the date of grant. The Black-Scholes option pricing model was used to estimate the weighted average fair value of each unit option granted with the following assumptions (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. At December 31, 2006, Atlas Pipeline Holdings had approximately $4.4 million of unrecognized compensation expense related to the unvested portion of the option units to be recognized over four years. The aggregate intrinsic value of stock options outstanding at December 31, 2006 was $1.6 million. There were no options that vested in 2006. The following table sets forth AHD LTIP's option unit activity for the year ended December 31, 2006:

	Year Ended December 31, 2006	
	Number of unit options	Weighted average exercise price
Outstanding - beginning of period	—	—
Granted [1]	1,215,000	$ 22.56
Exercised	—	—
Forfeited	—	—
Outstanding - end of period	1,215,000	$ 22.56

[1] The weighted average remaining contractual life for outstanding options was 9.3 years.

Atlas Pipeline Long-Term Incentive Plan. Atlas Pipeline has a Long-Term Incentive Plan ("APL LTIP"), in which officers, employees and non-employee managing board members of its general partner and employees of the general partner's affiliates are eligible to participate. Only phantom units have been granted under the APL LTIP through December 31, 2006. These units vest 25% at each anniversary date over a four year service period. Each unit entitles the grantee to one common unit upon vesting, as well as distribution equivalent rights ("DER") during the period the unit is outstanding. In 2006, the amount paid with respect to DERS was $400,000. Atlas Pipeline recognized $2 million, $485,000, $2.1 million and $700,000 in compensation expense related to the phantom units and their associated distributions for the year ended December 31, 2006, three months ended December 31, 2005 and twelve months ended September 30, 2005 and 2004, respectively. At December 31, 2006, Atlas Pipeline had approximately $4.3 million of unrecognized compensation expense related to the unvested portion of these awards to be recognized over four years. The aggregate intrinsic value of phantom units outstanding at December 31, 2006 was $7.6 million. There were no units that vested during the three months ended December 31, 2005 and year ended September 30, 2004. There were 14,581 units that vested during the year ended September 30, 2005.

NOTE 9 — BENEFIT PLANS – (Continued)

The following table represents the APL LTIP phantom unit activity for the year ended December 31, 2006:

	Year Ended December 31, 2006
Outstanding - beginning of period	110,128
Granted [1]	82,091
Vested	(31,152)
Forfeited	(2,000)
Outstanding - end of period	159,067

(1) The weighted average price for phantom unit awards on the date of grant, was $45.45, $48.59 and $37.15 for awards granted for the years ended December 31, 2006, September 30, 2005 and 2004, respectively. There were no units granted for the three months ended December 31, 2005.

Atlas Pipeline also 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 Atlas Pipeline upon achievement of pre-determined performance targets. Atlas Pipeline recognized $4.3 million, $461,000, $1.1 million and $0 for the year ended December 31, 2006, three months ended December 31, 2005, and twelve months ended September 30, 2005 and 2004, respectively, related to the vesting of awards under these incentive compensation agreements. At December 31, 2006, Atlas Pipeline had approximately $3.2 million of unrecognized compensation expense related to the unvested portion of these awards based on management's estimate of probable outcomes of performance targets.

Employee Stock Ownership Plan. In connection with the spin-off from RAI, the Company established an Employee Stock Ownership Plan ("ESOP") in June 2005. The ESOP, which is a qualified non-contributory retirement plan, was established to acquire shares of the Company's common stock for the benefit of all employees who are 21 years of age or older and have completed 1,000 hours of service for the Company. In addition, as a result of the spin-off, the ESOP holds 181,000 shares of RAI stock, all of which are allocated to participants. In June 2006, 107,800 RAI shares in the Company's ESOP were transferred to the RAI ESOP for 45,800 shares of Atlas America common stock in an even exchange. The Company loaned $602,000 (payable in quarterly installments of $18,508 plus interest at 7.5%) to the ESOP, which was used by the ESOP to acquire the remaining unallocated 40,375 shares of RAI common stock. Contributions to the ESOP are made at the discretion of the Company's Board of Directors. The cost of shares purchased by the ESOP but not yet allocated to participants is shown as a reduction of stockholders' equity. The unearned benefits expense (a reduction in stockholders' equity) will be reduced by the amount of any loan principal payments made by the ESOP to the Company. Any dividends which may be paid on allocated shares will reduce retained earnings; dividends on unearned ESOP shares will be used to service the related debt.

The common stock purchased by the ESOP with the money borrowed is held by the ESOP trustee in a suspense account. On an annual basis, as the ESOP loan is paid down, a portion of the common stock will be released from the suspense account and allocated to participating employees. As of December 31, 2006, there were 319,100 shares allocated to participants and 51,000 shares which are unallocated. Compensation expense related to the plan amounted to $114,000, $29,000, $30,000 and $0 for the year ended December 31, 2006, three months ended December 31, 2005 and twelve months ended September 30, 2005 and 2004, respectively. The fair value of unearned ESOP shares was $2.6 million at December 31, 2006.

Supplemental Employment Retirement Plan ("SERP"). In May 2004, the Company entered into an employment agreement with its Chairman of the Board, Chief Executive Officer and President, Edward E. Cohen, pursuant to which the Company has agreed to provide him with a SERP and with certain financial benefits upon termination of his employment. Under the SERP, Mr. Cohen will be paid an annual benefit equal to the product of (a) 6.5% multiplied by, (b) his base salary at the time of his retirement, death or other termination of employment with the Company, multiplied by, (c) the amount of years he shall be employed by the Company commencing upon the effective date of the SERP agreement, limited to an annual maximum benefit of 65% of his final base salary and a minimum of 26% of his final base salary. During the year ended December 31, 2006, three months ended December 31, 2005 and twelve months ended September 30, 2005 and 2004, operations were charged $381,000, $40,300, $161,000 and $59,500, respectively, with respect to this commitment.

NOTE 9 — BENEFIT PLANS – (Continued)

As of December 31, 2006, the actuarial present value of the expected postretirement obligation due under this the SERP was $1.3 million based upon an 8% interest rate.

As a result of the adoption of SFAS 158 at December 31, 2006, the Company was required to record an additional long-term liability of $683,000 for the difference between the expected postretirement benefit of $1.3 million and the accumulated postretirement obligation the Company had recognized as of December 31, 2006. The additional amount of this liability is recognized net of tax as an additional component of other comprehensive income.

The following table summarizes the incremental effects of the initial adoption of SFAS 158 to our Consolidated Balance Sheet at December 31, 2006:

	At December 31, 2006 (in thousands)		
	Before application of SFAS 158	SFAS 158 Adjustments	After application of SFAS 158
Other liabilities	$ 52,313	$ 683	$ 52,996
Deferred tax liability	30,457	(267)	30,190
Total liabilities	$ 82,770	$ 416	$ 83,186
Accumulated other comprehensive income	$ 8,842	$ (416)	$ 8,426
Total stockholder's equity	$ 132,662	$ (416)	$ 132,246

NOTE 10 — COMMITMENTS AND CONTINGENCIES

The Company leases office space and equipment under leases with varying expiration dates through 2014. Rental expense was $4.4 million, $1.3 million, $2.8 million and $1.1 million for the year ended December 31, 2006, three months ended December 31, 2005 and years ended September 30, 2005 and 2004 , respectively. Future minimum rental commitments for the next five years are as follows (in thousands):

2007	$ 4,318
2008	2,661
2009	806
2010	228
2011	152

The Company, through Atlas Energy, is the managing general partner of various energy partnerships, and has agreed to indemnify each investor partner from any liability that exceeds such partner's share of partnership assets. Subject to certain conditions, investor partners in certain energy partnerships have the right to present their interests for purchase by the Company, as managing general partner. Atlas Energy is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on past experience, the Company believes that any liability incurred would not be material.

Atlas Energy may be required to subordinate a part of its net partnership revenues from Atlas Energy's energy partnerships to the receipt by investor partners of cash distributions from the energy partnerships equal to at least 10% of their subscriptions determined on a cumulative basis, in accordance with the terms of the partnership agreements.

The Company is party to employment agreements with certain executives that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

NOTE 10 — COMMITMENTS AND CONTINGENCIES – (Continued)

One of the Company's subsidiaries, Resource Energy, LLC, together with Resource America, is a defendant in a class action originally filed in February 2000 in the New York Supreme Court, Chautauqua County, by individuals, putatively on their own behalf and on behalf of similarly situated individuals, who leased property to us. The complaint alleges that we are not paying landowners the proper amount of royalty revenues with respect to natural gas produced from the leased properties. The complaint seeks damages in an unspecified amount for the alleged difference between the amount of royalties actually paid and the amount of royalties that allegedly should have been paid. In October 2006 we reached a tentative settlement of this lawsuit, the settlement terms are subject to final approval by the court. Pursuant to the tentative settlement terms, we have agreed to pay $300,000, upgrade certain gathering systems and cap certain transportation expenses chargeable to the land owners.

The Company is also a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Company's financial condition or results of operations.

NOTE 11 — OPERATIONS OF ATLAS PIPELINE

In February 2000, the Company's natural gas gathering operations were sold to Atlas Pipeline in connection with a public offering by Atlas Pipeline of 1,500,000 common units. The Company received net proceeds of $15.3 million for the gathering systems, and Atlas Pipeline issued to the Company 1,641,026 subordinated units then constituting a 51% combined general and limited partner interest in Atlas Pipeline. A subsidiary of the Company is the general partner of Atlas Pipeline and has a 2% general partner interest on a consolidated basis. The Company's general partner interest also includes a right to receive incentive distributions if the partnership meets or exceeds specified levels of distributions.

In connection with the Company's sale of the gathering systems to Atlas Pipeline, the Company entered into an agreement that requires it to pay gathering fees to Atlas Pipeline for natural gas gathered by the gathering systems equal to the greater of $.35 per Mcf ($.40 per Mcf in certain instances) or 16% of the gross sales price of the natural gas transported. During all periods presented in the Company's consolidated financial statements, the fee paid to Atlas Pipeline was calculated based on the 16% rate.

The Company's subordinated units were a special class of limited partner interest in Atlas Pipeline under which its rights to distributions were subordinated to those of the publicly held common units. In January 2005, these subordinated units were converted to common units as Atlas Pipeline met stipulated financial tests under the terms of the partnership agreement allowing for such conversions. While the Company's rights as the holder of the subordinated units are no longer subordinated to the rights of the common unitholders, these units have not yet been registered with the Securities and Exchange Commission, and therefore, their resale in the public market is subject to restrictions under the Securities Act.

In June 2005, Atlas Pipeline completed a public offering of 2,300,000 units, realizing $91.7 million of offering proceeds, net of underwriting discounts, commissions and costs. In connection with this offering, the Company, as the general partner, contributed $1.9 million in order to maintain its 2% general partner interest.

In April and July 2004, Atlas Pipeline completed public offerings of 750,000 and 2,100,000 common units, respectively. The net proceeds after underwriting discounts, commissions and costs were $25.2 million and $67.9 million, respectively.

In September 2003, Atlas Pipeline entered into an agreement with SEMCO Energy, Inc. ("SEMCO") to purchase all of the stock of Alaska Pipeline. In order to complete the acquisition, Atlas Pipeline 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 Atlas Pipeline a notice purporting to terminate the transaction. Atlas Pipeline pursued its remedies under the acquisition agreement. In connection with the acquisition, subsequent termination and legal action, Atlas Pipeline incurred costs of approximately $4.0 million. On December 30, 2004, Atlas Pipeline entered into a settlement agreement with SEMCO settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline to Atlas Pipeline and SEMCO paid Atlas Pipeline $5.5 million. Atlas Pipeline 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 12 — ACQUISITIONS BY ATLAS PIPELINE

NOARK

On May 2, 2006, Atlas Pipeline acquired the remaining 25% equity 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, Atlas Pipeline 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 Atlas Pipeline'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, Atlas Pipeline 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

NOTE 12 — ACQUISITIONS BY ATLAS PIPELINE – (Continued)

Atlas Pipeline 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 Company's consolidated financial statements from its date of acquisition.

Spectrum

In July 2004, Atlas Pipeline 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 Company's consolidated financial statements from its date of acquisition.

Proforma results for the three months ended December 31, 2006 were not material to the Company's operations and therefore are not included. The following data presents unaudited pro forma revenues, net income and basic and diluted net income per share of common stock for the Company for the year ended September 30, 2005 as if the acquisitions discussed above, Atlas Pipeline's equity offerings, the net proceeds of which were utilized to repay debt borrowed to finance the acquisitions, and the issuance of $286.0 million of 8.125% Senior Notes (See Note 7), had occurred on October 1, 2004. The Company has prepared these 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 Atlas Pipeline had completed these acquisitions at October 1, 2004 or the results that will be attained in the future (in thousands, except per share amounts):

	Year Ended September 30, 2005		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 481,980	$ 174,943	$ 656,923
Net income	$ 32,940	$ (115)	32,825
Net income per common share outstanding – basic	$ 1.65	$ (.01)	$ 1.64
Weighted average common shares – outstanding basic	20,001	—	20,001
Net income per common share – diluted	$ 1.64	$ (.01)	$ 1.63
Weighted average common shares	20,049	—	20,049

NOTE 13 — OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS

The Company's operations include three reportable operating segments. These operating segments reflect the way the Company manages its operations and makes business decisions. The Company does not allocate income taxes to its operating segments. Operating segment data for the periods indicated are as follows (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Gas and Oil Production				
Revenues	$ 88,449	$ 24,086	$ 63,499	$ 48,526
Costs and Expenses	(8,499)	(1,721)	(6,044)	(5,265)
Segment Profit	$ 79,950	$ 22,365	$ 57,455	$ 43,261
Well Construction and Completion				
Revenues	$ 198,567	$ 42,145	$ 134,338	$ 86,880
Costs and Expenses	(172,666)	(36,648)	(116,816)	(75,548)
Segment Profit	$ 25,901	$ 5,497	$ 17,522	$ 11,332
Atlas Pipeline				
Revenues	$ 428,324	$ 127,334	$ 260,357	$ 30,037
Revenues – affiliates	30,257	7,930	21,929	17,190
Costs and Expenses	(360,869)	(109,851)	(229,764)	(27,817)
Segment Profit	$ 97,712	$ 25,413	$ 52,522	$ 19,410
Reconciliation of segment profit to net income before tax				
Segment profit				
Gas and oil production	$ 79,950	$ 22,365	$ 57,455	$ 43,261
Well construction and completion	25,901	5,497	17,522	11,332
Atlas Pipeline	97,712	25,413	52,522	19,410
Total segment profit	203,563	53,275	127,499	74,003
General and administrative expenses	(46,517)	(9,453)	(23,961)	(14,971)
Compensation reimbursement affiliate	(1,237)	(163)	(602)	(1,050)
Depreciation, depletion and amortization	(45,643)	(10,324)	(24,895)	(14,700)
Other income (expense) – net (a)	(40,836)	(14,725)	(25,083)	(10,686)
Net income before tax	$ 69,330	$ 18,610	$ 52,958	$ 32,596
Capital Expenditures				
Gas and oil production	$ 74,075	$ 16,610	$ 57,894	$ 32,172
Well construction and completion	—	—	—	—
Atlas Pipeline	83,831	14,622	40,061	7,910
Corporate and other	1,560	577	1,230	1,080
	$ 159,466	$ 31,809	$ 99,185	$ 41,162

	December 31, 2006	December 31, 2005
Balance Sheet		
Goodwill		
Gas and oil production	$ 21,527	$ 21,527
Well construction and completion	6,389	6,389
Atlas Pipeline	63,441	111,378
Corporate and other	7,250	7,250
	$ 98,607	$ 146,544
Total Assets		
Gas and oil production	$ 377,807	$ 256,210
Well construction and completion	8,335	8,428
Atlas Pipeline	787,128	736,977
Corporate and other	203,656	54,565
	$ 1,376,926	$ 1,056,180

NOTE 13 — OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS – (Continued)

(a) Includes revenues and expenses from well services, transportation and administration and oversight of ($3,804), ($2,524), ($3,662) and ($625) that do not meet the quantitative threshold for reporting segment information for the year ended December 31, 2006, three months ended December 31, 2005 and years ended September 30, 2005 and 2004, respectively.

Operating profit (loss) per segment represents total revenues less costs and expenses attributable thereto, excluding interest, provision for possible losses and depreciation, depletion and amortization, and general corporate expenses.

The Company's NGL's and natural gas are sold under contract to various purchasers. For the year ended December 31, 2006, sales to two customers accounted for approximately 22% and 12% of our total consolidated revenues. For the year ended September 30, 2005, NGL sales to one customer accounted for 20% of total consolidated revenues. For the year ended September 30, 2004 gas sales to Amerada Hess Corporation (formerly FirstEnergy Solutions Corp.) accounted for 11% of total revenues. No other operating segments had revenues from a single customer which exceeded 10% of total revenues.

NOTE 14 — COMMON STOCK

Stock split

On February 6, 2006, the Company's Board of Directors approved a three-for-two split of the Company's common stock effected in the form of a 50% stock dividend. All shareholders of record as of February 28, 2006 received one additional share of common stock for every two shares held on that date. The additional shares of common stock were distributed on March 10, 2006, in the form of a stock dividend. Information pertaining to shares and earnings per share has been restated in the accompanying financial statements and notes to the consolidated financial statements to reflect this split.

Dutch Auction Tender Offer

On January 30, 2007, the Company announced that the Board of Directors had authorized a "Dutch Auction" tender offer for up to 1,950,000 shares of the Company's common stock at an anticipated offer range of between $52.00 and $54.00 per share. The tender offer commenced on February 8, 2007 and will expire on March 9, 2007, unless extended by the Company.

The Company will select the lowest single per-share purchase price that will allow it to buy 1,950,000 million shares or, if a lesser number of shares is properly tendered, all shares that are properly tendered and not withdrawn. If the offer is over-subscribed, the Company will purchase first from shareholders owning fewer than 100 shares and tendering all of such shares at or below the purchase price determined by the Company and then from all other shareholders tendering at or below such purchase price on a pro rate basis. The tender offer will not be conditioned on any minimum number of shares being tendered.

Treasury Stock Repurchase Program

In November 2005, the Company announced that its Board of Directors authorized a repurchase program through which the Company might repurchase up to $50.0 million of its common stock. Repurchases were made from time to time through open market purchases or privately negotiated transactions at the discretion of the Company and in accordance with the rules of the Securities and Exchange Commission, as applicable. The Company repurchased 667,342 shares at a cost of $29.9 million during the year ended December 31, 2006.

NOTE 15 — SUBSEQUENT EVENT

On February 21, 2007, the Company's subsidiary, Atlas Lightfoot, LLC, invested $931,000 in Lightfoot Capital Partners LP and will own, directly and indirectly, approximately 18% of Lightfoot Capital Partners GP, LLC, the general partner of Lightfoot. The Company committed to invest a total of $20.0 million in Lightfoot. The Company will also receive certain co-investment rights until such point as Lightfoot raises additional capital through a private offering to institutional investors or a public offering.

NOTE 15 — SUBSEQUENT EVENT – (Continued)

Lightfoot has an initial equity funding commitments of approximately $160.0 million and intends to focus its investments primarily on incubating new master limited partnerships ("MLPs") and providing capital to existing MLPs in need of additional equity or structured debt. Lightfoot will concentrate on assets that are MLP-qualified such as infrastructure, coal, and other asset categories and intends to form new MLPs in partnership with premier management teams in sectors that have been under-utilized by the MLP structure.

NOTE 16 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Results of operations from oil and gas producing activities during the periods indicated are as follows (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Revenues	$ 88,449	$ 24,086	$ 63,499	$ 48,526
Production costs	(8,499)	(1,721)	(6,044)	(5,265)
Exploration expenses	(3,016)	(17)	(904)	(1,549)
Depreciation, depletion and amortization	(20,600)	(4,477)	(12,288)	(10,319)
Income taxes	(22,196)	(6,612)	(16,731)	(10,988)
Results of operations from oil and gas producing activities	$ 34,138	$ 11,259	$ 27,532	$ 20,405

Capitalized Costs Related to Oil and Gas Producing Activities. The components of capitalized costs related to the Company's oil and gas producing activities at the dates indicated are as follows (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Mineral interests:	$ 1,290	$ 2,308	$ 2,852	$ 2,544
Proved properties	1,002	1,002	1,002	1,002
Unproved properties	348,541	273,674	255,828	184,046
Wells and related equipment	5,541	4,170	3,644	2,890
Support equipment	51	51	51	1
Uncompleted well equipment and facilities	$ 356,425	$ 281,205	$ 263,377	$ 190,483
Accumulated depreciation, depletion and amortization	(83,182)	(71,032)	(66,536)	(54,086)
Results of operations from oil and gas producing activities	$ 273,243	$ 210,173	$ 196,841	$ 136,397

Costs Incurred in Oil and Gas Producing Activities. The costs incurred by the Company in its oil and gas activities during the periods indicated are as follows (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Property acquisition costs:				
Proved properties	$ 1,322	$ —	$ 308	$ 1,700
Unproved properties	—	—	—	439
Exploration Costs	6,847	1,312	904	1,549
Development Costs	76,687	17,380	72,308	39,978
	$ 84,856	$ 18,692	$ 73,520	$ 43,666

NOTE 16 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – (Continued)

The development costs above for the periods above were substantially all incurred for the development of proved undeveloped properties.

Oil and Gas Reserve Information (Unaudited). The estimates of the Company's proved and unproved gas reserves are based upon evaluations made by management and verified by Wright & Company, Inc., an independent petroleum engineering firm, as of December 31 2006 and 2005 and September 30, 2005 and 2004. All reserves are located within the United States. Reserves are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board which require that reserve estimates be prepared under existing economic and operating conditions with no provisions for price and cost escalation except by contractual arrangements.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

- Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation tests. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
- Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
- Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as "indicated additional reservoirs"; (b) crude oil, natural gas, and NGLs, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (c) crude oil, natural gas and NGLs, that may occur in undrilled prospects; and (d) crude oil and natural gas, and NGLs, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operation methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

There are numerous uncertainties inherent in estimating quantities of proven reserves and in projecting future net revenues and the timing of development expenditures. The reserve data presented represents estimates only and should not be construed as being exact. In addition, the standardized measures of discounted future net cash flows may not represent the fair market value of the Company's oil and gas reserves or the present value of future cash flows of equivalent reserves, due to anticipated future changes in oil and gas prices and in production and development costs and other factors for effects have not been proved.

NOTE 16 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – (Continued)

The Company's reconciliation of changes in proved reserve quantities is as follows (unaudited):

	Gas (Mcf)	Oil (Bbls)
Balance September 30, 2003	133,292,755	1,854,674
Current additions	28,761,902	245,509
Sales of reserves in-place	(3,439)	(1,669)
Purchase of reserves in–place	232,429	4,000
Transfers to limited partnerships	(10,132,616)	(29,394)
Revisions	(2,732,385)	382,613
Production	(7,285,281)	(181,021)
Balance September 30, 2004	142,133,365	2,274,712
Current additions	33,364,097	95,552
Sales of reserves in-place	(226,237)	(1,010)
Purchase of reserves in–place	116,934	575
Transfers to limited partnerships	(7,104,731)	(148,899)
Revisions	(2,631,044)	196,263
Production	(7,625,695)	(157,904)
Balance September 30, 2005	158,026,689	2,259,289
Current additions	8,357,940	36,931
Sales of reserves in-place	(59,873)	—
Purchase of reserves in–place	6,132	16
Transfers to limited partnerships	(4,740,605)	—
Revisions	(1,690,863)	653
Production	(1,975,070)	(39,678)
Balance December 31, 2005	157,924,350	2,257,211
Current additions	46,205,382	12,920
Sales of reserves in-place	(127,472)	(703)
Purchase of reserves in–place	305,433	1,675
Transfers to limited partnerships	(6,671,754)	(19,235)
Revisions	(20,147,989)	(33,594)
Production	(8,946,376)	(150,628)
Balance December 31, 2006	168,541,574	2,067,646
Proved developed reserves at:		
September 30, 2003	87,760,113	1,825,280
September 30, 2004	95,788,656	2,125,813
September 30, 2005	104,786,047	2,116,412
December 31, 2005	108,674,675	2,122,568
December 31, 2006	107,683,343	2,064,276

The following schedule presents the standardized measure of estimated discounted future net cash flows relating to proved oil and gas reserves. The estimated future production is priced at year-end prices, adjusted only for fixed and determinable increases in natural gas and oil prices provided by contractual agreements. The resulting estimated future cash inflows are reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels and includes the effect on cash flows of settlement of asset retirement obligations on gas and oil properties. The future net cash flows are reduced to present value amounts by applying a 10% discount factor. The standardized measure of future cash flows was prepared using the prevailing economic conditions existing at the dates presented and such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of recoverable reserves or in estimating future results of operations (unaudited) (in thousands).

NOTE 16 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – (Continued)

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Future cash inflows	$ 1,262,161	$ 1,874,432	$ 2,503,644	$ 1,096,047
Future production costs	(334,062)	(290,600)	(296,015)	(227,738)
Future development costs	(149,610)	(107,784)	(117,256)	(92,079)
Future income tax expense	(225,082)	(445,004)	(607,624)	(227,862)
Future net cash flows	553,407	1,031,044	1,482,749	548,368
Less 10% annual discount for estimated timing of cash flows	(347,887)	(601,772)	(876,052)	(315,370)
Standardized measure of discounted future net cash flows	$ 205,520	$ 429,272	$ 606,697	$ 232,998

The future cash flows estimated to be spent to develop proved undeveloped properties in the years ended December 31, 2007, 2008 and 2009 are $48.1 million, $50.8 million and $50.7 million, respectively.

The following table summarizes the changes in the standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes (unaudited) (in thousands):

	Year Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended September 30, 2005	Years Ended September 30, 2004
Balance, beginning of year	$ 429,272	$ 606,697	$ 232,998	$ 144,351
Increase (decrease) in discounted future net cash flows:				
Sales and transfers of oil and gas, net of related costs	(79,950)	(21,645)	(55,333)	(41,237)
Net changes in prices and production costs	(273,631)	(245,838)	417,798	97,161
Revisions of previous quantity estimates	(30,058)	(4,571)	(6,073)	6,265
Development costs incurred	3,426	2,727	4,224	4,838
Changes in future development costs	(8,505)	(1,159)	(1,577)	(1,033)
Transfers to limited partnerships	(8,449)	(8,563)	(24,750)	(9,499)
Extensions, discoveries, and improved recovery less related costs	44,820	22,597	154,215	54,979
Purchases of reserves in-place	660	24	596	594
Sales of reserves in-place, net of tax effect	(572)	(243)	(672)	(33)
Accretion of discount	59,714	21,141	32,038	19,142
Net changes in future income taxes	93,137	71,614	(151,882)	(40,504)
Estimated settlement of asset retirement obligations	(8,226)	(848)	(12,763)	(1,757)
Estimated proceeds on disposals of well equipment	10,007	998	12,740	2,055
Other	(26,125)	(13,659)	5,138	(2,324)
Balance, end of year	$ 205,520	$ 429,272	$ 606,697	$ 232,998

NOTE 17 — QUARTERLY RESULTS (Unaudited)

	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
		(in thousands, except per share data)		
Year ended December 31, 2006				
Revenues	$ 192,459	$ 164,810	$ 190,617	$ 201,420
Income from continuing operations before income taxes	$ 18,033	$ 17,758	$ 16,272	$ 17,267
Net income	$ 11,361	$ 10,100	$ (19,876)	$ 14,416
Net income per common share – basic	$ 0.57	$ 0.51	$ (1.01)	$ 0.75
Net income per common share – diluted	$ 0.56	$ 0.50	$ (.99)	$ 0.73

	December 31 2004	March 31, 2005	June 30, 2005	September 30, 2005
		(in thousands, except per share data)		
Year ended September 30, 2005				
Revenues	$ 92,850	$ 104,484	$ 128,155	$ 156,208
Income from continuing operations before income taxes	$ 13,894	$ 13,307	$ 12,013	$ 13,744
Net income	$ 8,892	$ 8,516	$ 6,444	$ 9,088
Net income per common share – basic	$ .43	$ .43	$ .32	$ .45
Net income per common share – diluted	$ .43	$ .43	$ .32	$ .45

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 Atlas America, Inc., 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 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 can not be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.
Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective as of December 31, 2006. 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Atlas America, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Atlas America, Inc. (a Delaware corporation) and subsidiaries ("the Company") maintained effective 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). The Company'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 Company'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 provides a reasonable basis for our opinions.

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also in our opinion, the Company maintained, in all material respects, effective 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).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company and its subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, changes in stockholders' equity and cash flows for year ended December 31, 2006, the three month period ended December 31, 2005 and for the years ended September 30, 2005 and 2004, and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements.

/s/ Grant Thornton LLP

Cleveland, Ohio
February 28, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Our Board of Directors are divided into three classes with directors in each class serving three year terms. There are no family relationships among the directors and executive officers except that Edward E. Cohen, our Chairman, Chief Executive Officer and President, is the father of Jonathan Z. Cohen, the Vice Chairman of our Board of Directors. The following table sets forth information regarding our executive officers and directors:

Name	Age	Position	Term Expires
Edward E. Cohen	67	Chairman, Chief Executive Officer and President	2008
Jonathan Z. Cohen	36	Vice Chairman	2007
Matthew A. Jones	45	Chief Financial Officer	—
Frank P. Carolas	47	Executive Vice President	—
Freddie M. Kotek	50	Executive Vice President	—
Jeffrey C. Simmons	48	Executive Vice President	—
Michael L. Staines	57	Executive Vice President	—
Nancy J. McGurk	51	Senior Vice President and Chief Accounting Officer	—
Carlton M. Arrendell	43	Director	2007
William R. Bagnell	42	Director	2009
Donald W. Delson	54	Director	2009
Nicholas A. DiNubile	53	Director	2009
Dennis A. Holtz	65	Director	2008
Harmon S. Spolan	71	Director	2008

Edward E. Cohen has been the Chairman of our Board of Directors, our Chief Executive Officer and President since our formation in September 2000. Mr. Cohen has been the Chairman of the Board and Chief Executive Officer of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc., since their formation in June 2006. Mr. Cohen has been the Chairman of the Managing Board of Atlas Pipeline Partners GP, LLC, the general partner of Atlas Pipeline Partners, L.P., since its formation in 1999, and Chairman of the Board and Chief Executive Officer of Atlas Pipeline Holdings GP, LLC, the general partner of Atlas Pipeline Holdings, L.P., since its formation in January 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 our Board of Directors since our formation. Mr. Cohen has been Vice Chairman of the Board of Atlas Energy Resources and Atlas Energy Management since their formation in June 2006. Mr. Cohen has been Vice Chairman of the Managing Board of Atlas Pipeline Partners GP since its formation in 1999 and Vice Chairman of the Board of Atlas Pipeline Holdings GP since its formation in January 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 the trustee and secretary of RAIT Financial Trust (a publicly-traded real estate investment trust) from 1997, and its Vice Chairman from 2003, until December 2006. Mr. Cohen is a son of Edward E. Cohen.

Matthew A. Jones has been our Chief Financial Officer and the Chief Financial Officer of Atlas Pipeline Partners GP since March 2005. Mr. Jones has been the Chief Financial Officer and a director of Atlas Energy Resources since its formation in June 2006 and has been the Chief Financial Officer of Atlas Pipeline Holdings GP since January 2006 and a director since February 2006. 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.

Frank P. Carolas has been an Executive Vice President since January 2001 and served as a director from January 2002 until February 2004. Mr. Carolas has been a Senior Vice President of Atlas Energy Management since its formation in June 2006. Mr. Carolas was a Vice President of Resource America from April 2001 until May 2004, and has been Executive Vice President—Land and Geology and a director of Atlas Resources, LLC (Atlas Energy Resources' wholly-owned subsidiary which acts as the managing partner of its drilling partnerships) since January 2001. Mr. Carolas is a certified petroleum geologist and has been employed by Atlas Resources and its affiliates since 1981.

Freddie M. Kotek has been an Executive Vice President since February 2004 and served as a director from September 2001 until February 2004. Mr. Kotek has been Chairman of Atlas Resources since September 2001 and Chief Executive Officer and President of Atlas Resources since January 2002. Mr. Kotek was our Chief Financial Officer from February 2004 until March 2005. Mr. Kotek was a Senior Vice President of Resource America from 1995 until May 2004, President of Resource Leasing, Inc. (a wholly-owned subsidiary of Resource America) from 1995 until May 2004.

Jeffrey C. Simmons has been an Executive Vice President since January 2001 and was a director from January 2002 until February 2004. Mr. Simmons has been a Senior Vice President of Atlas Energy Management since its formation in June 2006 and Executive Vice President—Operations and a director of Atlas Resources since January 2001. Mr. Simmons was a Vice President of Resource America from April 2001 until May 2004. Mr. Simmons joined Resource America in 1986 as a senior petroleum engineer and has served in various executive positions with its and our energy subsidiaries since then.

Michael L. Staines has been an Executive Vice President since our formation. Mr. Staines has been President of Atlas Pipeline Partners GP since January 2001 and its Chief Operating Officer and a member of its Managing Board since its formation in November 1999. Mr. Staines was a Senior Vice President of Resource America from 1989 until May 2004, a director from 1989 to February 2000 and Secretary from 1989 to October 1998.

Nancy J. McGurk has been our Chief Accounting Officer since January 2001, Senior Vice President since January 2002, and served as our Chief Financial Officer from January 2001 until February 2004. Ms. McGurk has been Senior Vice President of Atlas Resources since January 2002 and Chief Financial Officer and Chief Accounting Officer since January 2001. Ms. McGurk was a Vice President of Resource America from 1992 until May 2004, and its Treasurer and Chief Accounting Officer from 1989 until May 2004.

Richard D. Weber has been President, Chief Operating Officer and a director of Atlas Energy Resources and President, Chief Operating Officer and a director of Atlas Energy Management since their formation in June 2006. Mr. Weber served from June 1997 until March 2006 as Managing Director and Group Head of the Energy Group of KeyBanc Capital Markets, a division of KeyCorp, and its predecessor, McDonald & Company Securities, Inc., where he oversaw activities with oil and gas producers, pipeline companies and utilities.

Independent Directors

The following directors have been determined by our board to be independent directors as defined under NASDAQ rules and the Securities Act.

Carlton M. Arrendell has been a director since February 2004. Mr. Arrendell currently serves as a special real estate consultant to the AFL-CIO Investment Trust Corporation following six years of service as Investment Trust Corporation's Chief Investment Officer. Mr. Arrendell has been with Investment Trust Corporation since 1996.

William R. Bagnell has been a director since February 2004. Mr. Bagnell has been involved in the energy industry in various capacities since 1986. He has been Vice President—Energy for Planalytics, Inc. (an energy industry risk management and software company) since March 2000, and was Director of Sales for Fisher Tank Company (a national manufacturer of carbon and stainless steel bulk storage tanks) from September 1998 to January 2000. Before that, he served as Manager of Business Development for Buckeye Pipeline Partners, L.P. (a refined petroleum products transportation company) from October 1992 until September 1998. Mr. Bagnell served as an independent member of the Managing Board of Atlas Pipeline Partners GP from its formation in November 1999 until May 2004.

Donald W. Delson has been a director since February 2004. Mr. Delson has over 20 years of experience as an investment banker specializing in financial institutions. Mr. Delson has been a Managing Director, Corporate Finance Group, at Keefe, Bruyette & Woods, Inc. since 1997, and before that was a Managing Director in the Corporate Finance Group at Alex. Brown & Sons from 1982 to 1997. Mr. Delson served as an independent member of the Managing Board of Atlas Pipeline Partners GP from June 2003 until May 2004.

Nicholas A. DiNubile has been a director since February 2004. Dr. DiNubile has been an orthopedic surgeon specializing in sports medicine since 1982. Dr. DiNubile has served as special advisor and medical consultant to the President's Council on Physical Fitness and as Orthopedic Consultant to the Philadelphia 76ers basketball team. Dr. DiNubile is also Clinical Assistant Professor of the Department of Orthopedic Surgery at the Hospital of the University of Pennsylvania.

Dennis A. Holtz has been a director since February 2004. Mr. Holtz has maintained a corporate law practice with D.A. Holtz, Esquire & Associates in Philadelphia and New Jersey since 1988.

Harmon S. Spolan has been a director since August 2006. Since January 2007, Mr. Spolan has served as of counsel to the law firm Cozen O'Connor, where he is chairman of the firm's charitable foundation. From 1999 until January 2007, Mr. Spolan was a member of the firm and served as chairman of its Financial Services Practice Group and as co-marketing partner. Prior to joining Cozen O'Connor, Mr. Spolan served as President, Chief Operating Officer, and a director of JeffBanks, Inc., and its subsidiary bank for 22 years. Mr. Spolan has served as director of TRM Corporation since June 2002.

Information Concerning the Audit Committee

Our Board of Directors has a standing Audit Committee. All of the members of the Audit Committee are independent directors as defined by NASDAQ rules. The members of the Audit Committee are Messrs. Arrendell, Bagnell and Delson, with Mr. Arrendell acting as the chairman. Our Board of Directors has determined that Mr. Delson 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our officers, directors and persons who own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC and to furnish us with copies of all such reports.

Based solely on our review of the reports we have received, or written representations from certain reporting persons that no filings were required for those persons, we believe that during fiscal 2006 our executive officers, directors and greater than 10% stockholders complied with all applicable filing requirements of Section 16(a) of the Securities Exchange Act, except Ms. McGurk inadvertently filed one Form 4 late.

Code of Ethics

We have adopted a code of business conduct and ethics applicable to all directors, officers and employees. We believe we meet the definition of a code of ethics under the Securities Act. Our code of business conduct and ethics is available on our web site at **www.atlasamerica.com.**

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management and, based on its review and discussions, the Compensation Committee recommended to the board of directors that the Compensation Discussion and Analysis be included in this annual report on Form 10K.

This report has been provided by the Compensation Committee of the Board of Directors of Atlas America, Inc.

Donald W. Delson, Chairman
Dennis A. Holtz
Carlton M. Arrendell

COMPENSATION DISCUSSION AND ANALYSIS

Our Compensation Committee is responsible for formulating and presenting recommendations to our Board of Directors with respect to the compensation of our named executive officers. The Compensation Committee is also responsible for administering our employee benefit plans, including incentive plans. The Compensation Committee is comprised solely of independent directors, consisting of Messrs. Delson, Arrendell and Holtz, with Mr. Delson acting as the chairperson.

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 the company and its various publicly-traded subsidiaries, as appropriate.

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

Our 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 to our named executive officers individually and as a group. Mercer was asked to review compensation we awarded during 2005 and to assist the Compensation Committee in its analysis of 2006 awards. Because of the importance to our company of our direct-placement energy investment programs and our creation of new publicly-traded entities, Mercer and the Compensation Committee looked not only to the oil and energy industry (adjusted for scope by position) in evaluating our compensation levels but also, as appropriate, to the financial services industry.

In particular, we focused on our company's equity performance, market capitalization, corporate developments (especially the generation of cash proceeds for us from the creation of new public companies), our business performance (including production of energy and replacement of reserves), and our financial position. The Compensation Committee noted the following:

- our stock price increased 27% during the fiscal year ending December 2006, far exceeding both the S&P Small-Cap 500 Energy Index (which increased only 1%) and that of the S&P Mid-Cap 400 GICS Oil & Gas Index (which increased by only 1%) during 2006, our market capitalization rose by almost $200 million, representing a 23% increase;

- our completion of two initial public offerings—AHD in July 2006 and ATN in December 2006—generating almost $200 million in cash, after taxes and expenses;
- despite a substantial decline in natural gas prices during the year, earnings per share before tax on gain on APL Holdings increased 30% in 2006, total revenues increased 54% over revenues in 2005, earnings before interest, income taxes, depreciation and amortization were up by 59% and net income before tax on gain on APL Holdings increased by 28%;
- our activities during the year resulted in an ending cash position of $185.4 million and 324.2 million in debt, compared with the December 2005 cash position of $55.2 and $298.8 million in debt; and
- our named executive officers' responsibilities are very broad: our senior executives as a group are responsible for four public companies having over $3 billion in market capitalization.

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 the company's 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 our Board of Directors.

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 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 our success 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) confirmed that the base salaries paid to the named executive officers in fiscal 2006 fall between the median and the 75th 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 our annual performance and/or to the performance of one of our subsidiaries or divisions for which he or she is responsible. Additionally, the annual incentive allows us to recognize an individual's performance in relation to our performance or that of one of our subsidiaries or divisions. Generally, the higher the level of responsibility of the executive within our company, 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 both the company and individual, including initiatives undertaken by our named executive officers, during the year.

Section 162(m) of the Internal Revenue Code generally disallows a tax deduction to public companies for compensation in excess of $1 million paid to the chief executive officer and four other most highly paid executive officers. Qualifying performance-based compensation is not subject to the deduction limitation if certain requirements are met. The new annual incentive plan that our Compensation Committee has recommended and that our Board of Directors has adopted, and recommended for approval by our shareholders at our upcoming annual meeting, will comply with the performance-based exemptions under Section 162(m).

Long-Term Incentives

We believe that our long term success depends upon aligning executives' and shareholders' interests. To support this objective, we provide our executives with various means to become significant shareholders, including our long-term incentive programs and those of our public subsidiaries. These 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. Certain of our named executive officers perform work for one or more of our publicly-traded subsidiaries and, accordingly, are rewarded for their performance under the long-term incentive plan of the subsidiaries for which they perform services. In the case of Mr. Weber, we awarded 50,000 options under our Stock Incentive Plan ("our Plan") in fiscal 2006 pursuant to the terms of his employment agreement. There was no set formula for granting awards to any other named executive officer, and we did not award grants under our Plan to any of them during the fiscal year because the Compensation Committee determined that the awards granted in prior years were sufficient. However, some of those named executive officers were awarded grants under the Atlas Pipeline Partners Long-Term Incentive Plan (the "APL Plan") and under the Atlas Pipeline Holdings Long-Term Incentive Plan (the "AHD Plan"): Messrs. E. Cohen, J. Cohen, and Jones were granted phantom units under the APL 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.

As discussed above, the Compensation Committee has considered the implications of Section 162(m) of the Internal Revenue Code in making decisions concerning compensation design and administration. The Compensation Committee views tax deductibility as an important consideration and intends to maintain deductibility where possible but also believes that our business needs should be the overriding driver of compensation design. We retain the flexibility to authorize compensation that may not be deductible if we believe it is in the best interests of our company. The Compensation Committee also considers tax implications for executives and structures its compensation programs to comply with Section 409A of the Internal Revenue Code.

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 other than Mr. E. Cohen, and perquisites are discouraged. None of our named executive officers have deferred any portion of their compensation.

Employment Agreements

Generally, we do not favor employment agreements unless they are required to attract or to retain executives to the organization. We have entered into employment agreements with Messrs. E. Cohen and Weber. Employment agreements with these named executive officers were essential to attract and/or retain their services.

Compensation Determination

In determining compensation amounts awarded, the Compensation Committee focused on specific contributions by the named executive officers to our overall performance during 2006:

- Mr. E. Cohen was a critical force in all of our significant initiatives as well as the significant initiatives of our subsidiaries, including, the successful initial public offerings of AHD and Atlas Energy Resources.
- Mr. J. Cohen was responsible for some of our most important initiatives, including the formation of and our investment in Lightfoot Capital Partners, a master limited partnership (a "MLP") that will develop a portfolio of MLP-qualifying assets.
- Mr. Jones's investment banking expertise was instrumental in the successful completion of the initial public offerings of Atlas Pipeline Holdings and Atlas Energy Resources, revolving credit facilities for each of them totaling $300 million, the placement of $40 million of Atlas Pipeline Partners convertible preferred units, the add-on offering to Atlas Pipeline Partners' senior unsecured notes, and Atlas Pipeline Partners' follow-on equity offering.
- We hired Mr. Weber in April 2006 to launch and become the President and Chief Operating Officer of Atlas Energy Resources. Based upon the success of Atlas Energy Resources' initial public offering, which priced at the top of the anticipated price range, we increased his bonus over the amount specified in his employment contract.
- Mr. Kotek is responsible for our direct-placement energy investment programs. In calendar 2006, Mr. Kotek was responsible for raising $218.5 million in funds, representing a 39.2% increase in funds raised from calendar 2005.

SUMMARY COMPENSATION TABLE

The following table sets forth information concerning the compensation for fiscal 2006 for our Chief Executive Officer, Chief Financial Officer and each of our other three most highly compensated executive officers whose aggregate salary and bonus (including amounts of salary and bonus foregone to receive non cash compensation) exceeded $100,000.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	Option Awards ($) (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Edward E. Cohen, Chairman of the Board and Chief Executive Officer	2006	$600,000	$ 1,400,000	$ 2,974,200	$ 1,880,000	$ 121,769(3)	$ 41,849 (4)	$ 7,017,818
Matthew A. Jones, Chief Financial Officer	2006	$300,000	$ 750,000	$ 687,150	$ 376,000	—	$ 65,602 (5)	$ 2,178,752
Jonathan Z. Cohen, Vice Chairman	2006	$400,000	$ 1,000,000	$ 1,722,550	$ 752,000	—	$ 20,400 (6)	$ 3,894,950
Freddie M. Kotek, Executive Vice President	2006	$300,000	$ 350,000	—	—	—	$ 10,867 (7)	$ 660,867
Richard D. Weber, President and Chief Operating Officer of Atlas Energy Resources, LLC	2006	$201,923	$ 800,000	—	$1,055,000(8)	—	$ 26,957 (9)	$ 2,083,750

(1) Represents (i) phantom units granted under the APL Plan, valued in accordance with FAS 123R at the closing market price of Atlas Pipeline Partners' common units on the November 1, 2006 grant date of $47.19 per common unit, as follows: Mr. E. Cohen – 20,000 units; Mr. J. Cohen – 15,000 units; and Mr. Jones – 5,000 units; and (ii) phantom units granted under the AHD Plan, valued in accordance with FAS 123R at the closing market price of Atlas Pipeline Holdings' common units on the November 10, 2006 grant date of $22.56 per common unit, as follows: Mr. E. Cohen - 90,000; Mr. J. Cohen - 45,000; and Mr. Jones - 20,000.

(2) Represents options granted under the AHD Plan, 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; and Mr. Jones – 100,000.

(3) Represents the aggregate annual change in the actual present-value of accumulated pension benefits under the Supplemental Employment Retirement Plan for Mr. E. Cohen, which we are in the process of funding.

(4) Represents payments on distribution equivalent rights ("DERs") of $17,000 with respect to the phantom units awarded under the APL Plan and $15,300 with respect to phantom units awarded under the AHD Plan, as reported in the Stock Awards column. Also includes matching contributions to Mr. E. Cohen's 401(k) account of $8,682 and a company contribution of $867 to Mr. E. Cohen's ESOP account.

(5) Includes payments on DERs of $4,250 with respect to the phantom units awarded under the APL Plan and $3,400 with respect to phantom units awarded under the AHD Plan, as reported in the Stock Awards column, and $49,585 for reimbursements for rental payments on Mr. Jones's temporary residence. Also, includes matching contributions of $7,500 to Mr. Jones's 401(k) account and a company contribution of $867 to Mr. Jones's ESOP account.

(6) Represents payments on DERs of $12,750 with respect to the phantom units awarded under the APL Plan and $7,650 with respect to phantom units awarded under the AHD Plan, as reported in the Stock Awards column.

(7) Represents matching contributions of $10,000 to Mr. Kotek's 401(k) account and a company contribution of $867 to Mr. Kotek's ESOP account.

(8) Represents options granted under our Plan, valued at $21.10, per share using the Black – Scholes option pricing model to estimate the weighted average fair value of each option granted for 50,000 shares with weighted average assumptions for (a) expected dividend yield of $-0-, (b) risk-free interest rate of 4.8%, (c) expected volatility of 35%, and (d) an expected life of 6.25 years.

(9) Represents reimbursement of relocation expenses of $22,836 for Mr. Weber and his family to the Pittsburgh area and the lease value method calculation for personal use of the company vehicle of $4,121.

2006 GRANTS OF PLAN-BASED AWARDS TABLE

Name	Grant Date	Approval Date	All Other Stock Awards: Number of Shares Of Stock or Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Sh)
Edward E. Cohen	11/1/06	10/31/06	20,000 (1)	—	—
	11/10/06	10/31/06	90,000 (2)	500,000 (3)	$ 22.56
Matthew A. Jones	11/1/06	10/31/06	5,000 (1)	—	—
	11/10/06	10/31/06	20,000 (2)	100,000 (3)	$ 22.56
Jonathan Z. Cohen	11/1/06	10/31/06	15,000 (1)	—	—
	11/10/06	10/31/06	45,000 (2)	200,000 (3)	$ 22.56
Richard Weber	4/17/06	4/3/06	—	50,000 (4)	$ 47.86

(1) Represents grants of phantom units under the APL Plan, which vest 25% per year on the anniversary of the grant.

(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.

(3) Represents grants of stock options under the AHD Plan, which vest, which vest 25% on the third anniversary and 75% on the fourth anniversary of the grant.

(4) Represents grants of stock options under our Plan, in accordance with Mr. Weber's employment agreement, which vest 25% per year on the anniversary of the commencement of Mr. Weber's employment on April 17, 2006, except as described below under "—Employment Agreements—Richard D. Weber."

Employment Agreements

Edward E. Cohen

We entered into an employment agreement with Edward E. Cohen, who currently serves as our Chairman, Chief Executive Officer and President, in May 2004. The agreement requires him to devote such time to us as is reasonably necessary to the fulfillment of his duties, although it permits him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $350,000 per year, which may be increased by the Compensation Committee based upon its evaluation of Mr. Cohen's performance. Mr. Cohen is eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment. The agreement has a term of three years and, until notice to the contrary, the term is automatically extended so that on any day on which the agreement is in effect it has a then-current three-year term.

The agreement provides for a Supplemental Executive Retirement Plan, or SERP, pursuant to which Mr. Cohen will receive; upon the later of his retirement or reaching the age of 70, an annual retirement benefit equal to the product of:

- 6.5% multiplied by
- his base salary as of the time Mr. Cohen's employment with us ceases, multiplied by
- the number of years (or portions thereof) which Mr. Cohen is employed by us but, in any case, not less than four.

The maximum benefit under the SERP is limited to 65% of his final base salary. The benefit is guaranteed to his estate for up to 10 years if he should die before receiving 10 years' of SERP benefits. If there is a change of control, Mr. Cohen resigns for good reason, or if we terminate his employment without cause, then the SERP benefit will be the greater of the accrued benefit pursuant to the above formula, or 40% of his final base salary.

The agreement provides the following regarding termination and termination benefits:

- Upon termination of employment due to death, Mr. Cohen's estate will receive (a) a lump sum payment in an amount equal to his final base salary multiplied by the number of years (or portion thereof) that he shall have worked for us (but not to be greater than 3 years' base salary or less than one year's base salary), (b) payment of his SERP benefit and (c) automatic vesting of all stock and option awards.
- We may terminate Mr. Cohen's employment if he is disabled for 180 days consecutive days during any 12-month period. If his employment is terminated due to disability, he will receive (a) his base salary for 3 years, and such 3 year period will be deemed a portion of his employment term for purposes of accruing SERP benefits, (b) continuation of term life and health insurance then in effect for 3 years, or an amount equal to Mr. Cohen's after tax cost of continuing such coverage where such coverage cannot be continued, (c) payment of his SERP

benefit, (d) automatic vesting of all stock and option awards and (e) after such 3 year period, any amounts payable under our long-term disability plan.

- We may terminate Mr. Cohen's employment without cause upon 30 days' written notice or upon a change of control after providing at least 30 days' written notice. He may terminate his employment for good reason or upon a change of control. Good reason is defined as a reduction in his base pay, a demotion, a material reduction in his duties, relocation, his failure to be elected to our Board of Directors or a material breach of the agreement by us. If employment is terminated by us without cause, by Mr. Cohen for good reason or by either party in connection with a change of control, he will be entitled to either (a) if Mr. Cohen does not sign a release, severance benefits under our then current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to 3 years of his average compensation (which we define as the average of the 3 highest years of total compensation that he shall have earned under the agreement, or if the agreement is less than three years old, the highest total compensation in any year or portion thereof), (ii) continuation of term life and health insurance then in effect for 3 years, or an, amount equal to Mr. Cohen's after tax cost of continuing such coverage where such coverage cannot be continued, (iii) payment of his SERP benefit and (iv) automatic vesting of all stock and option awards.
- Mr. Cohen may terminate the agreement without cause with 60 days notice to us, and if he signs a release, he will receive (a) a lump sum payment equal to one-half of one year's base salary then in effect, (b) automatic vesting of all stock and option awards and (c) if he has reached retirement age, his SERP benefits.
- We may terminate his employment for cause (defined as a felony conviction or conviction of a crime involving fraud, embezzlement or moral turpitude, intentional and continual failure to perform his material duties after notice, or violation of confidentiality obligations), in which case he will receive only accrued amounts then owed to him.

Change of control is defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act of 1934, of 25% or more of our voting securities or all or substantially all of our assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;
- we consummate a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) our directors immediately prior to the transaction constitute less than a majority of the board of the surviving entity, unless $^1/_2$ of the surviving entity's board were our directors immediately prior to the transaction and our chief executive officer immediately prior to the transaction continues as the chief executive officer of the surviving entity; or (b) our voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of us, the surviving entity or, in the case of a division, each entity resulting from the division;
- during any period of 24 consecutive months, individuals who were Board members at the beginning of the period cease for any reason to constitute a majority of the Board, unless the election or nomination for election by our stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or
- our shareholders approve a plan of complete liquidation of winding up of our company, or agreement of sale of all or substantially all of our assets or all or substantially all of the assets of our primary subsidiaries to an unaffiliated entity.

In the event that any amounts payable to Mr. Cohen upon termination become subject to any excise tax imposed under Section 4999 of the Internal Revenue Code, we must pay Mr. Cohen an additional sum such that the net amounts retained by Mr. Cohen, after payment of excise, income and withholding taxes, equals the termination amounts payable, unless Mr. Cohen's employment terminates because of his death or disability.

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

Reason for termination	Lump sum severance payment	SERP[(1)]	Benefits[(2)]	Accelerated vesting of stock awards and option awards[(3)]	Tax gross-up[(4)]
Death	$ 1,547,154[(5)]	$ 2,340,000	$ 30,391	$ 5,089,200	$ —
Disability	1,547,154[(5)]	2,340,000	42,192	5,089,200	—
Termination by us without cause[(6)]	1,547,154[(5)]	2,340,000	42,192	5,089,200	—
Termination by Mr. Cohen for good reason[(6)]	4,947,154[(7)]	2,340,000	42,192	5,089,200	—
Change of control[(6)]	4,947,154[(7)]	2,340,000	42,192	5,089,200	937,019
Termination by Mr. Cohen without cause	300,000[(8)]	2,340,000	—	5,089,200	—

(1) Represents the value of vested benefits payable calculated by multiplying the per year benefit by the minimum of 10 years.

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

(3) Represents the value of unvested and accelerated option awards and stock 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 stock on December 29, 2006. The payments relating to stock awards are calculated by multiplying the number of accelerated shares or units by the closing price of the applicable stock on December 29, 2006.

(4) Under the SEC Executive Compensation Disclosure rule (number 33-8732A) the Company is obligated to disclose payment an additional amount or Gross-Up Payment such that the net amount retained by the executive after deduction of any excise tax imposed under section 4999 of the Code, and any federal, state and local income tax, FICA and Medicare withholding taxes and excise tax imposed upon the Gross Up Payment, shall be equal to the Payment. The computation takes into account the 20% excess parachute payment rate and a 42.65% combined effective tax rate.

(5) Calculated as the sum of the amount of Mr. Cohen's base salary for the 2004, 2005 and 2006 fiscal years.

(6) These amounts are contingent upon Mr. Cohen executing a release. If Mr. Cohen does not execute a release he would receive severance benefits under our current severance plan.

(7) Calculated as the sum of the amount of Mr. Cohen's base salary and bonuses for the 2004, 2005 and 2006 fiscal years.

(8) Represents ½ of Mr. Cohen's 2006 base salary.

Richard D. Weber

We entered into an employment agreement in April 2006 with Richard Weber, who serves as President and Chief Operating Officer of Atlas Energy and Atlas Energy Management. The agreement has a two year term and, after the first year, the term automatically renews daily so that on any day that the agreement is in effect, the agreement will have a remaining term of one year. Mr. Weber is required to devote substantially all of his working time to Atlas Energy Management and its affiliates. The agreement provides for an annual base salary of not less than $300,000 and a bonus of not less than $700,000 during the first year. After that, bonuses will be awarded solely at the discretion of our Compensation Committee. The agreement provides for equity compensation as follows:

- Upon execution of the agreement, Mr. Weber was granted options to purchase 50,000 shares of our stock at $47.86.
- In January 2007, Mr. Weber received a grant of 47,619 shares of restricted units of Atlas Energy with a value of $1,000,000.
- In January 2007, Mr. Weber received options to purchase 373,752 common units of Atlas Energy at $21.00.

All of the securities described above vest 25% per year on each anniversary of the date Mr. Weber commenced his employment, April 17, 2006. All securities will vest immediately upon a change of control or termination by Mr. Weber for good reason or by Atlas Energy Management other than for cause. Change of control is defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 50% or more of our or Atlas Energy Resources' voting securities or all or substantially all of our or Atlas Energy Resources' assets by a single person or entity or group of affiliated persons or entities, other than an entity of which either Mr. E. Cohen or Mr. J. Cohen is an officer, manager, director or participant;
- we or Atlas Energy Resources consummate a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity after which Atlas Energy Management is not the manager of Atlas Energy Resources; or

- our or Atlas Energy Resources' shareholders approve a plan of complete liquidation of winding up, or agreement of sale of all or substantially all of our or Atlas Energy Resources' assets other than an entity of which either Mr. E. Cohen or Mr. J. Cohen is an officer, manager, director or participant.

The reason for the change of control triggering events relating to the disaffiliation of Messrs. Cohen from our company or Atlas Energy Resources is that Mr. Weber believed that Messrs. Cohen effectively controlled us at the time of his employment and their separation from us would therefore constitute a change of control. Good reason is defined as a material breach of the agreement, reduction in his base pay, a demotion, a material reduction in his duties or his failure to be elected to the Atlas Energy Resources Board of Directors. Cause is defined as fraud in connection with his employment, conviction of a crime other than a traffic offense, material failure to perform his duties after written demand by our Board or breach of the representations made by Mr. Weber in the employment agreement if the breach impacts his ability to fully perform his duties.

Atlas Energy Management may terminate Mr. Weber without cause upon 45 days written notice or for cause upon written notice. Mr. Weber may terminate his employment for good reason or for any other reason upon 30 days' written notice. Key termination benefits are as follows:

- If Mr. Weber's employment is terminated due to death, Atlas Energy Management will (a) pay to Mr. Weber's designated beneficiaries a lump sum cash payment in an amount equal to the bonus that Mr. Weber received from the prior fiscal year pro rated for the time employed during the current fiscal year and (b) Mr. Weber's family will receive health insurance coverage for one year.
- If Mr. Weber's employment is terminated by Mr. Weber other than for good reason, all stock and option awards will automatically vest.
- If Atlas Energy Management terminates Mr. Weber's employment other than for cause, or, Mr. Weber terminates his employment for good reason, (a) Atlas Energy Management will pay amounts and benefits otherwise payable to Mr. Weber as if Mr. Weber remained employed for one year, except that the bonus amount shall be prorated and based on the bonus awarded in the prior fiscal year, and (b) all stock and option awards will automatically vest.

Mr. Weber is entitled to a gross-up payment if any payments made to him would constitute an excess parachute payment under Section 280G of the Code such that the net amount Mr. Weber receives after the deduction of any excise tax, any federal, state and local income tax, and any FICA and Medicare withholding tax is the same amount he would have received had such taxes not been deducted. The agreement includes standard restrictive covenants for a period of two years following termination, including non-compete and non-solicitation provisions.

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

Reason for termination	Lump sum severance payment	Benefits[(1)]	Accelerated vesting of stock awards and option awards[(2)]	Tax gross-up
Death	$ 800,000 [(3)]	$ 18,185	$ —	$ —
Disability	—	22,131	—	—
Termination by us without cause (including for disability) or by Mr. Weber for good reason	1,923[(4)]	22,131	1,055,000	—
Change of control	—	—	1,055,000	—
Termination by Mr. Weber without cause	—	—	—	—

(1) Represents rates currently in effect for COBRA insurance benefits for 12 months.

(2) Represents the value of unvested and accelerated option awards disclosed in the "Outstanding Equity Awards at Fiscal Year-End Table," calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of our stock on December 29, 2006.

(3) Calculated as the sum of Mr. Weber's 2006 base salary and bonus.

(4) Represents Mr. Weber's 2006 bonus.

Long-Term Incentive Plans

Our Plan authorizes the granting of up to 2.0 million shares of our common stock to our employees, affiliates, consultants and directors in the form of incentive stock options ("ISOs"), 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 our 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 our common stock upon vesting. Awards under our 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 each of 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 the Company or death or disability of a grantee, provided the grantee has completed at least six months service.

Eligible participants in the Atlas Energy Resources Long-Term Incentive Plan (the "ATN Plan") are the employees, directors and consultants of Atlas Energy Management and its affiliates, including us, who perform services for Atlas Energy Resources. Awards under the ATN Plan may be phantom units, unit options and tandem DERs with respect to phantom units for an aggregate of 3,600,000 common units. The long-term incentive plan is administered by our Compensation Committee under delegation from the Atlas Energy Resources board. Awards under the ATN Plan generally become exercisable as to 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant.

<u>APL Plan</u>

Officers, employees and non-employee managing board members of Atlas Pipeline Partners' general partner and employees of the general partner's affiliates and consultants are eligible to receive awards under the APL Plan of either phantom units or unit options for an aggregate of 435,000 common units. The APL Plan is administered by our Compensation Committee under delegation from the general partner's managing board. Currently, only phantom units have been issued under the APL Plan.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Compensation Committee, cash equivalent to the fair market value of a common unit. In addition, the Compensation Committee may grant a participant a 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 Atlas Pipeline Partners makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase common units at an exercise price determined by the Compensation Committee at its discretion. Except for phantom units awarded to non-employee managing board members of the general partner, the Compensation Committee determines the vesting period for phantom units and the exercise period for options. Through December 31, 2006, phantom units granted under the APL Plan 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 Compensation Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members of the general partner vest over a four year period. Awards will automatically vest upon a change of control, as defined in the APL Plan.

<u>AHD Plan</u>

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 our 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 Board approved grants under the AHD Plan conditioned upon the filing of a Registration Statement on Form S-8.

2006 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)	$ 477,600 (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)
Freddie M. Kotek	15,000 (16)	45,000 (17)	$ 22.57	7/1/2015	750 (18)	$ 36,000 (3)
Richard D. Weber	—	50,000 (19)	$ 47.86	4/17/2016	—	—

(1) Represents 450,000 options to purchase our stock, granted on 7/1/05, which vested immediately.

(2) Represents Atlas Pipeline Partners 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 Atlas Pipeline Partners 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 30,000 options to purchase our stock.

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

(9) Represents Atlas Pipeline Partners 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 Atlas Pipeline Holdings 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 300,000 options to purchase our stock, granted on 7/1/05, which vested immediately.

(13) Represents Atlas Pipeline Partners 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 15,000 options to purchase our stock.

(17) Represents options to purchase our stock, which vest as follows: 7/1/07 – 15,000; 7/1/08 – 15,000 and 7/1/09 – 15,000.

(18) Represents Atlas Pipeline Partners phantom units, which vest as follows: 3/16/07–250; 3/16/08–250 and 3/16/09 – 250.

(19) Represents options to purchase our stock (all of which are reported in "2006 Grants of Plan-Based Awards Table"), which vest as follows: 4/17/07 – 12,500; 4/17/08 – 12,500; 4/17/09 – 12,500 and 4/17/10 – 12,500.

2006 OPTION EXERCISES AND STOCK VESTED TABLE

	Stock Awards	
Name	Number of Shares Acquired on Vesting (1)	Value Realized on Vesting ($)
Edward E. Cohen	11,250	$ 454,612
Matthew A. Jones	3,750	$ 151,537
Jonathan Z. Cohen	6,875	$ 277,819
Freddie M. Kotek	250	$ 10,102

(1) Represents Atlas Pipeline Partners common units.

2006 PENSION BENEFITS TABLE

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Edward E. Cohen	SERP	4	$ 1,324,614	—

For a description of Mr. Cohen's SERP, please see "Employment Agreements - Edward E. Cohen", and for a discussion of the valuation method and material assumptions applied in quantifying the present value of the accumulated benefit, please see note 9 to our Consolidated Financial Statements.

2006 DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Total ($)
Dennis A. Holtz	$ 32,000	$ 15,000(1)	$ 37,000
Carlton M. Arrendell	$ 20,625	$ 14,981(1)	$ 35,606
Nicholas A. DiNubile	$ 30,500	$ 14,981(1)	$ 45,481
William R. Bagnell	$ 30,500	$ 14,981(1)	$ 45,481
Donald W. Delson	$ 32,000	$ 14,981(1)	$ 46,981
Harmon S. Spolan	$ 12,434	$ 14,987(2)	$ 27,421

(1) Represents 317 deferred shares granted to each of Messrs. Holtz, Arrendell, DiNubile, Bagnell and Delson. The shares vest one-third on each of the second, third and fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 5/14/07 – 731; 5/14/08 – 836; 5/14/09 – 838; 5/14/10 – 355; 5/14/11 – 107.

(2) Mr. Spolan was granted a stock award of 331 shares on August 24, 2006. The vesting schedule for Mr. Spolan's award is as follows: 8/24/08 – 110; 8/24/09 – 110; 8/24/10 – 111.

Director Compensation

Prior to July 26, 2006, in addition to a monthly retainer of $1,000, the independent directors received additional monthly fees for acting as chairperson of a committee and for being a member of a committee. The independent directors also received a fee for each board meeting attended. Upon approval by the full board of directors, after July 26, 2006, the independent directors received a flat fee of $35,000 per year. In addition to the cash compensation, independent directors receive an annual grant of deferred stock having a fair market value of $15,000 with a vesting schedule in which 33% of the award vests on the second anniversary of the grant date and 33% of the award vests on the following two anniversaries.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the Board of Directors consists of Messrs. Delson, Arrendell and Holtz. There are no Compensation Committee interlocks.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the number and percentage of shares of our common stock owned by beneficial owners of 5% or more of our common stock, by our executive officers and directors and by all of the executive officers and directors as a group as of February 27, 2007. The address for each director and executive officer is 311 Rouser Road, P.O. Box 611, Moon Township, Pennsylvania 15108.

	Common Stock		
	Amount and Nature of Beneficial Ownership [2]		Percent of Class
Beneficial Owner[1]			
Directors			
Carlton M. Arrendell	483		*
William R. Bagnell	0		—
Edward E. Cohen	1,910,186	(3)(5)	9.87%
Jonathan Z. Cohen	1,006,569	(4)(5)	5.20%
Donald W. Delson	483		—
Nicholas A. DiNubile	1,983		*
Dennis A. Holtz	1,554		*
Harmon S. Spolan	331		*
Non-Director Executive Officers			
Frank P. Carolas	30,020	(5)	*
Freddie M. Kotek	120,161	(5)	*
Matthew A. Jones	30,011	(5)	*
Nancy J. McGurk	41,181	(5)	*
Jeffrey C. Simmons	72,449	(5)	*
Michael L. Staines	68,312	(5)	*
All executive officers and directors as a group (14 persons)	2,748,372	(6)	14.20%
Other Owners of More Than 5% of Outstanding Shares			
Cobalt Capital Management, Inc.	2,039,872	(7)	10.54%
Magnetar Financial LLC	1,789,855	(8)	9.25%
Leon G. Cooperman	1,407,818	(9)	7.27%

* Less than 1%

(1) The business address for each director and executive officer is 311 Rouser Road, Moon Township, Pennsylvania 15108.

(2) All shares reflect a 3-for-2 stock split which we completed on March 10, 2006.

(3) Includes (i) 22,424 shares held in an individual retirement account of Betsy Z. Cohen, Mr. E. Cohen's spouse, (ii) 581,313 shares held by a charitable foundation of which Mr. E. Cohen, his spouse and their children serve as co-trustees; and (iii) 120,300 shares held in trust for the benefit of Mr. E. Cohen's spouse and/or children. Mr. E. Cohen disclaims beneficial ownership of the above referenced shares. 57,465 and 581,313 shares are also included in the shares referred to in footnote 4 below.

(4) Includes (i) 57,465 shares held in a trust of which Mr. J. Cohen is a co-trustee and co-beneficiary and (ii) 581,313 shares held by a charitable foundation of which Mr. J. Cohen, his parents and his sibling serve as co-trustees. These shares are also included in the shares referred to in footnote 3 above. Mr. J. Cohen disclaims beneficial ownership of the above referenced shares.

(5) Includes shares issuable on exercise of options granted under our Stock Incentive Plan in the following amounts: Mr. E. Cohen — 450,000 shares; Mr. J. Cohen — 300,000 shares; Mr. Carolas — 11,250 shares; Mr. Kotek — 15,000 shares; Mr. Jones — 30,000 shares; Ms. McGurk – 1,875 shares; Mr. Simmons — 11,250 shares; and Mr. Staines — 1, 875 shares.

(6) This number has been adjusted to exclude 57,465 shares and 581,313 shares which were included in both Mr. E. Cohen's beneficial ownership amount and Mr. J. Cohen's beneficial ownership amount.

(7) This information is based on a Schedule 13G/A filed with the SEC on February 14, 2007. The address for Cobalt Capital Management, Inc. is 237 Park Avenue, Suite 900, New York, New York 10017.

(8) This information is based on a Schedule 13G filed with the SEC on February 14, 2007. The address for Magnetar Financial LLC is 1603 Orrington Avenue, 13th floor, Evanston, Illinois 60210.

(9) This information is based on a Schedule 13G/A filed with the SEC on February 14, 2007. The address for Mr. Cooperman is 88 Pine Street, Wall Street Plaza, 31st Floor, New York, New York 10005.

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

We have the following agreements with Resource America, our former parent, for which Edward E. Cohen, our Chairman, Chief Executive Officer and President, serves as Chairman and is a greater than 10% shareholder, and Jonathan Z. Cohen, our Vice Chairman, serves as Chief Executive Officer and President.

Tax Matters Agreement

As part of our initial public offering in 2004, we entered into a tax matters agreement with Resource America, which governs our respective rights, responsibilities, and obligations of after our initial public offering with respect to tax liabilities and benefits, tax attributes, tax contests and other matters regarding income taxes, non-income taxes and related tax returns.

In general, under the tax matters agreement:

- Resource America is responsible for any U.S. federal income taxes of the affiliated group for U.S. federal income tax purposes of which Resource America is the common parent. With respect to any periods beginning after our initial public offering, we are responsible for any U.S. federal income taxes attributable to us or any of our subsidiaries, including taxes payable as a result of our June 2005 spin-off from Resource America.
- Resource America is responsible for any U.S. state or local income taxes reportable on a consolidated, combined or unitary return that includes Resource America or one of its subsidiaries, on the one hand, and us or one of our subsidiaries, on the other hand. However, in the event that we or one of our subsidiaries are included in such a group for U.S. state or local income tax purposes for periods (or portions thereof) beginning after the date of our initial public offering, we are responsible for our portion of such income tax liability as if we and our subsidiaries had filed a separate tax return that included only us and our subsidiaries for that period (or portion of a period).
- Resource America is responsible for any U.S. state or local income taxes reportable on returns that include only Resource America and its subsidiaries (excluding us and our subsidiaries), and we are responsible for any U.S. state or local income taxes filed on returns that include only us and our subsidiaries.
- Resource America and we are each responsible for any non-income taxes attributable to our business for all periods.

Resource America is primarily responsible for preparing and filing any tax return with respect to the Resource America affiliated group for U.S. federal income tax purposes and with respect to any consolidated, combined or unitary group for U.S. state or local income tax purposes that includes Resource America or any of its subsidiaries. We generally are responsible for preparing and filing any tax returns that include only us and our subsidiaries.

We have generally agreed to indemnify Resource America and its affiliates against any and all tax-related liabilities that may be incurred by them relating to the distribution to the extent such liabilities are caused by our actions. This indemnification applies even if Resource America has permitted us to take an action that would otherwise have been prohibited under the tax-related covenants as described above.

During 2006, we did not have any liability to Resource America pursuant to the tax matters agreement.

Transition Services Agreement

Also in connection with our initial public offering, we entered into a transition services agreement with Resource America which governs the provision support services between us, such as:

- cash management and debt service administration;
- accounting and tax;
- investor relations;

- payroll and human resources administration;
- legal;
- information technology;
- data processing;
- real estate management; and
- other general administrative functions.

We and Resource America will pay each other a fee for these services equal to their fair market value. The fee is payable monthly in arrears, 15 days after the close of each month. We have also agreed to pay or reimburse each other for any out-of-pocket payments, costs and expenses associated with these services. During fiscal 2006, we reimbursed Resource America $1.2 million pursuant to this agreement. Certain operating expenditures totaling $117,000 that remain to be settled between are reflected in our consolidated balance sheets as advances from affiliate.

Anthem Securities, until December 2006 our wholly-owned subsidiary and now a wholly-owned subsidiary of Atlas Energy, is a registered broker-dealer which provides dealer-manager services for investment programs sponsored by Resource America's real estate and equipment finance segments. Salaries of the personnel performing services for Anthem are paid by Resource America, and Anthem reimburses Resource America for the allocable costs of such personnel. In addition, Resource America agreed to cover some of the operating costs for Anthem's office of supervisory jurisdiction, principally licensing fees and costs. In fiscal 2006, Resource America paid $1.3 million toward such operating costs of Anthem and Anthem reimbursed it $2.7 million.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For the years ended December 31, 2006 and 2005, Grant Thornton LLP's accounting fees and services (in thousands) were as follows.

	2006	2005
Audit fees[(1)]	$ 1,721	$ 888
Audit-related fees[(2)]	18	2
Tax fees[(3)]	76	-
All other fees[(4)]	-	-
Total accounting fees and services	$ 1,815	$ 890

(1) Audit fees include professional services rendered for the annual audit of our financial statements and for the reviews of the financial statements included in our quarterly reports on Form 10-Q.

(2) Represents fees related to public offering matters,

(3) There were no fees for tax services rendered to us during the year ended December 31, 2005.

(4) There were no other fees rendered to us during the years ended December 31, 2006 and 2005.

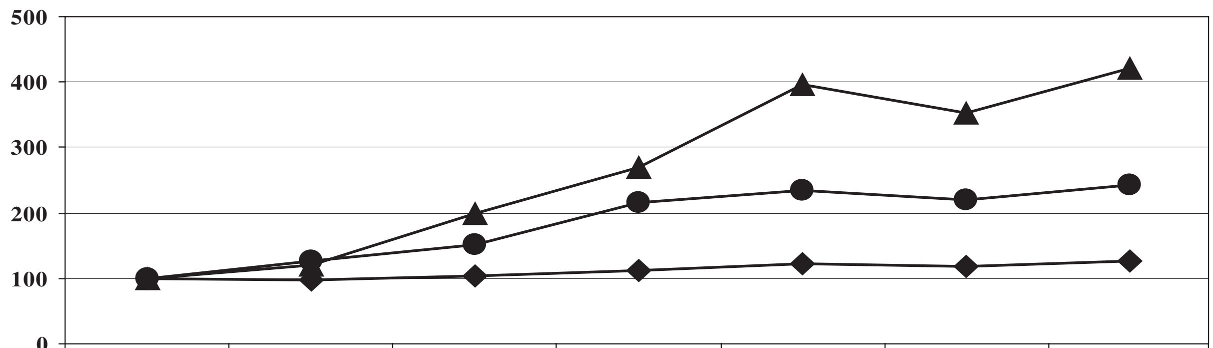
Audit Committee Pre-Approval Policies and Procedures

The Audit Committee, on at least an annual basis, reviews audit and non-audit services performed by Grant Thornton, LLP as well as the fees charged by Grant Thornton, LLP for such services. Our policy is that all audit and non-audit services must be pre-approved by the Audit Committee. All of such services and fees were pre-approved during 2006 and 2005.

Performance Graph

The following graph compares that cumulative total stockholder return on the Company's common stock with the cumulative total return of two other stock market indices: the Nasdaq United States Composite and S&P Small-Cap 600 Energy Index.

Comparison of Cumulative Total Return Since IPO *



5/11/2004	9/30/2004	3/31/2005	9/30/2005	3/31/2006	9/30/2006	12/31/2006
100.00	98.25	103.52	112.14	122.07	118.26	126.44
100.00	127.47	152.17	216.35	235.01	219.33	242.53
100.00	120.01	199.39	269.29	395.34	352.92	421.47

Fiscal Year Ended December 31

Nasdaq U.S. composite — S&P Small-Cap 600 Energy Index — Atlas America, Inc.

*Total return since the Company's initial public offering. Assumes $100 was invested on May 11, 2004 in the Company's common stock or in the indicated index and that cash dividends were reinvested as received.