ATLAS PIPELINE PARTNERS LP
Form 10-K
March 16, 2005

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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION
13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13
OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM _________ TO __________

COMMISSION FILE NUMBER: 1-14998

ATLAS PIPELINE PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

DELAWARE	23-3011077
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
311 ROUSER ROAD MOON TOWNSHIP, PENNSYLVANIA	15108
(Address of principal executive office)	(Zip code)

Registrant's telephone number, including area code: (412) 262-2830
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units of Limited Partnership Interest	New York Stock Exchange

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

N/A

Title of class

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2) of the Act. Yes [X] No [ ]

The aggregate market value of the equity securities held by non-affiliates of the registrant, based on the closing price on June 30, 2004 was approximately $124.7 million.

DOCUMENTS INCORPORATED BY REFERENCE
None

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
INDEX TO ANNUAL REPORT
ON FORM 10-K

PART I

ITEM 1. DESCRIPTION OF BUSINESS

THE FOLLOWING DISCUSSION CONTAINS FORWARD-LOOKING STATEMENTS REGARDING EVENTS AND FINANCIAL TRENDS WHICH MAY AFFECT OUR FUTURE OPERATING RESULTS AND FINANCIAL POSITION. SUCH STATEMENTS ARE SUBJECT TO RISKS AND UNCERTAINTIES THAT COULD CAUSE OUR ACTUAL RESULTS AND FINANCIAL POSITION TO DIFFER MATERIALLY FROM THOSE ANTICIPATED IN THESE FORWARD-LOOKING STATEMENTS. THESE FACTORS INCLUDE FLUCTUATIONS IN THE MARKET FOR NATURAL GAS FROM WHICH OUR REVENUES ARE DERIVED, PRODUCTION DECLINES FROM WELLS SERVICED BY OUR GATHERING SYSTEMS, REDUCED DRILLING FOR NEW WELLS IN OUR SERVICE AREAS AND OUR NEED FOR ADDITIONAL CAPITAL TO EXPAND OUR GATHERING SYSTEMS.

GENERAL

We are a Delaware limited partnership with common units traded on the New York Stock Exchange under the symbol "APL." We own and operate approximately 3,280 miles of natural gas pipeline gathering systems through our operating partnership and its operating subsidiaries. Our pipeline systems currently consist of approximately 1,380 miles of intrastate gathering systems located in the Appalachian Basin in eastern Ohio, western New York and western Pennsylvania and 1,900 miles of intrastate gathering systems in southern Oklahoma and northern Texas. We have expanded our gathering systems both through extensions to connect new natural gas supplies and through acquisitions. In addition, we own and operate a natural gas processing facility in Velma, Oklahoma. Our gathering systems currently serve approximately 5,100 wells with an average daily throughput for the years ended December 31, 2004, 2003 and 2002 of 109.8 million cubic feet, or mmcf, 52.5 mmcf and 50.4 mmcf of natural gas, respectively. Our gathering systems provide a means through which well owners and operators can transport the natural gas produced by their wells to public utility pipelines for delivery to customers. To a lesser extent, our gathering systems transport natural gas directly to customers.

We originally acquired the gathering systems of Atlas America, Inc. (NASDAQ:ATLS) and its affiliates, all of which are subsidiaries of Resource America, Inc. (NASDAQ: REXI), when we commenced operations in January 2000. We refer to the Resource America energy subsidiaries with which we have contractual relationships, including Atlas America, collectively as "Atlas America," unless specifically stated otherwise. Atlas America and its affiliates sponsor limited and general partnerships to raise funds from investors to explore for natural gas, and produce natural gas and, to a lesser extent, oil from locations in eastern Ohio, western New York and western Pennsylvania. Our Appalachian Basin gathering systems are connected to 4,500 of those wells. Atlas America drilled and connected 335 wells to our Appalachian Basin gathering systems during the year ended December 31, 2004, 270 wells during the year ended December 31, 2003 and 195 wells during the year ended December 31, 2002.

We are party to an omnibus agreement with Atlas America that is intended to maximize the use and expansion of our gathering systems and the amount of natural gas they transport. Among other things, the omnibus agreement requires Atlas America to install required flow lines and connect wells it operates that are located within 2,500 feet of one of our gathering systems.

We are also party to natural gas gathering agreements with Atlas America under which it pays us gathering fees generally equal to a percentage, generally 16%, of the gross or weighted average sales price of the natural gas we transport subject, in certain cases, to minimum prices of $.35 or $.40 per thousand cubic feet, or mcf. Our business, therefore, depends in large part on the prices at which the natural gas we transport is sold. Due to the volatility of natural gas prices, our gross revenues can vary materially from period to period.

Acquisition of Spectrum Field Services, Inc. In July 2004, we acquired Spectrum Field Services, Inc., or Spectrum, which changed its name to Atlas Pipeline Mid-Continent, LLC. ("APLMC"), for approximately $142.4 million, including transaction costs and taxes due as a result of the transaction. This acquisition significantly increased our size and diversifies the natural gas supply basins in which we operate and the natural gas midstream services we provide to our customers. Spectrum was a natural gas gathering and processing company headquartered in Tulsa, Oklahoma. APLMC's business includes gathering natural gas from oil and gas wells and processing this raw natural gas into merchantable natural gas, or residue gas, by extracting natural gas liquids, or NGLs, and removing impurities. APLMC sells natural gas to purchasers at the tailgate of our gas plant located in Velma, Oklahoma, and sells its NGLs to Koch Hydrocarbon at the plant under an agreement that is renewed monthly. APLMC's principal assets consist of a gas processing plant in Velma, Oklahoma and approximately 1,100 miles of active and 760 miles of inactive natural gas gathering pipelines in south central Oklahoma and north Texas. APLMC has more than 650 separate gas purchase contracts. Of these, approximately 75% (by volume) are percentage of proceeds, or POP, contracts. Under its POP purchasing arrangements, APLMC 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. Unlike "keep whole" contracts, which require the processor to bear the economic risk (called the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that the processor paid for the unprocessed natural gas, POP contracts protect the processor against processing margin risk. The remaining 20% of APLMC's purchase and gathering contracts are fixed fee, under which APLMC receives a fee for gathering, compressing, treating and processing natural gas. During the year ended December 31, 2004, APLMC processed an average of 56.4 million cubic feet, or mmcf, per day of natural gas and produced an average of 5,799 bbls per day of NGLs. The majority of APLMC's natural gas supply is from relatively long-lived, mid-continent casinghead gas production.

We financed the Spectrum acquisition, including approximately $4.2 million of transaction costs, as follows:

- borrowing $100.0 million under the term loan portion of our $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association;

- using the $20.0 million of net proceeds received from the sale to Resource America and Atlas America of preferred units in our operating subsidiary; and

- using $22.4 million of the net proceeds from our April 2004 common unit offering.

We used a portion of the net proceeds of our July 2004 offering to repay $40.0 million of the borrowings under our new credit facility and to repurchase for $20.4 million the preferred units issued to Resource America and Atlas America.

Public Offerings. In April and July 2004, we completed public offerings of 750,000 and 2,100,000 common units of limited partner interest. The net proceeds after underwriting discounts and commissions were approximately $25.2 million and $67.5 million, respectively. Our general partner simultaneously contributed $535,000 and $1.5 million to us in order to maintain its 2% general partner interest in us.

Settlement of Alaska Pipeline Company Arbitration. In September 2003, we entered into an agreement with SEMCO Energy, Inc. to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, we 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 us a notice purporting to terminate the transaction. We pursued our remedies under the acquisition agreement. In connection with the acquisition, subsequent termination, and settlement of the legal action, we incurred costs of approximately $4.0 million in the year ended December 31, 2004. On December 30, 2004, we entered into a settlement agreement with SEMCO settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline Company to us and SEMCO paid us $5.5 million. We show this settlement, net of expenses on our Consolidated Statement of Income as Gain on arbitration settlement, net.

Distribution Increases. In February, 2004, we paid a quarterly cash distribution of $0.625 per common unit (an annualized rate of $2.50 per common unit). In December 2004, the managing board of our general partner approved an increase in the quarterly cash distribution to $0.72 per common unit (an annualized rate of $2.88 per common unit). There can be no assurance we will be able to generate sufficient available cash to make distributions at this level.

APPALACHIAN OPERATIONS

Public utility pipelines charge transportation fees to the entity having title to the natural gas being transported, typically the well owner, an intermediate purchaser such as a natural gas distribution company, or a final purchaser. We do not have title to the natural gas gathered and delivered by us and, accordingly, do not pay transportation fees charged by public utility pipelines. We do not transport any oil produced by wells connected to our gathering systems.

We are party to an omnibus agreement with Atlas America, Inc. that is intended to maximize the use and expansion of our gathering systems and the amount of natural gas they transport. Among other things, the omnibus agreement requires Atlas America to install required flow lines and connect wells it operates that are located within 2,500 feet of one of our gathering systems.

We are also party to natural gas gathering agreements with Atlas America under which it pays us gathering fees generally equal to a percentage, generally 16%, of the gross or weighted average sales price of the natural gas we transport subject, in most cases, to minimum prices of $0.35 or $0.40 per thousand cubic feet, or mcf. Our business, therefore, depends in large part on the prices at which the natural gas we transport is sold. Due to the volatility of natural gas prices, our gross revenues can vary materially from period to period. During the year ended December 31, 2004, we received gathering fees averaging $0.96 per mcf, while during the years ended December 31, 2003 and 2002, our average gathering fees were $0.82 and $0.58 per mcf, respectively.

MID-CONTINENT OPERATIONS

Natural Gas and NGL Supply and Sales

ChevronTexaco is APLMC's largest supplier of natural gas under a contract that has a life-of-lease or 10-year term expiring in 2010 with a year-to-year renewal provision. The 236 wells under ChevronTexaco's contract supply approximately 10.0 million cubic feet, (mmcf) per day to the APLMC system. APLMC retains a weighted average of 47% of the NGL revenues and a weighted average of 10% of the residue gas revenues from sales of this gas. APLMC's remaining gas contracts have varying terms: the latest expiration date is 2008, with a few scheduled to terminate in 2005. The term of others has expired, but the producers continue to sell the gas under the year-to-year renewal provisions.

In February, 2004, Spectrum entered into a contract with Zinke & Trumbo to gather and process natural gas from a new development northwest of Duncan, Oklahoma. In March 2004, Spectrum completed a 29-mile, large-diameter high pressure trunkline to connect this new gas supply. The Duncan line is currently delivering nine mmcf of natural gas per day.

APLMC sells its NGL production to Koch Hydrocarbons at the Velma gas plant under an agreement that is renewed monthly. Spectrum has the right to elect (on a monthly basis) whether the NGLs are sold into the Mont Belvieu or Conway markets. NGLs are priced at the average monthly Oil Price Information Service price for the selected market. In addition, this agreement provides for a fee which is based upon the Houston Ship Channel spot-gas price and fluctuates monthly from $0.0125 and $0.015 per gallon for deliveries to Mont Belvieu.

APLMC also has a transportation and fractionation contract with Koch Hydrocarbons, which expires in January 2006. Condensate is collected at both the Velma gas plant and in the Velma gathering system and sold for APLMC's account to SemGroup, L.P. under an agreement with a primary term which expired on November 30, 2004 and continues on a month-to-month basis.

APLMC sells natural gas to purchasers at the tailgate of the Velma gas plant. During the year ended December 31, 2004 and 2003, ONEOK Energy Marketing and Trading accounted for 31% and 85%, respectively, of Spectrum's residue natural gas sales and Tenaska Marketing Ventures accounted for 12% and 15% of such sales, respectively. APLMC currently sells the majority of its residue natural gas at the average of ONEOK Gas Transmission and Southern Star Central first-of-month indices as published in Inside FERC, with the remainder being sold on a NYMEX basis, less a fixed basis differential.

Natural Gas and NGL Hedging

APLMC also uses hedges to limit its exposure to changing natural gas and NGL prices. These hedges include floating-for-fixed swaps and collars. In a floating-for-fixed swap, APLMC sells future production to the counterparty at a fixed price and agrees to purchase production from the counterparty at a price that will be established on the date of hedge settlement by reference to a specified index price. In a collar, APLMC purchases a put option for specified production quantities while simultaneously selling a call option on the same amount of production. These hedges cover periods of up to two years from the date of the hedge. To insure that these financial instruments will be used solely for hedging price risks and not for speculative purposes, APLMC has established a hedging committee to review its hedges for compliance with its hedging policies and procedures. In addition, APLMC does not enter into a hedge where it cannot offset the hedge with physical residue natural gas or NGL sales.

The portion of residue natural gas and NGLs that APLMC hedges and the manner in which it is hedged changes from time to time. As of December 31, 2004, APLMC's hedging position for future months through December 31, 2006 for its residue and NGL production was approximately as follows:

- 43% was hedged under floating-for-fixed swaps;
- 10% was hedged with collars; and
- 47% was not hedged and was subject to market-based pricing.

APLMC 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 APLMC sells the physical residue natural gas or NGLs. All of APLMC's hedges are characterized as cash flow hedges as defined in Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Accounting." APLMC 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 uses daily closing NYMEX prices when applicable and an internally-generated algorithm for hedged commodities that are not traded on a market.

For information on our revenues, net income and total assets, please see "Item 6. Selected Financial Data."

CREDIT FACILITIES

Concurrently with the completion of the Spectrum acquisition, in July 2004, we entered into a $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank that replaced our $20.0 million facility. The facility originally included a $35.0 million four year revolving line of credit and a $100.0 million five year term loan. Upon the completion of our July 2004 public offering, we repaid $40.0 million of the $100.0 million term loan we had borrowed in order to complete the acquisition of Spectrum, and in December 2004, we repaid an additional $15.0 million by borrowing $10.0 million on our revolving line of credit. In August 2004 and December 2004, the revolving credit portion of the facility was increased to $75.0 million and $90.0 million, respectively. Up to $5.0 million of the facility may be used for standby letters of credit. Borrowings under the facility are secured by a lien on and security interest in all of our property and that of our subsidiaries and by the guaranty of each of our subsidiaries. The credit facility bears interest at one of two rates, elected at our option:

- the base rate plus the applicable margin; or

- the adjusted LIBOR plus the applicable margin.

The base rate for any day equals the higher of the federal funds rate plus 1/2 of 1% or the Wachovia Bank prime rate. The applicable margin for the revolving line of credit is as follows:

- where our leverage ratio, that is, the ratio of our debt to our earnings before interest, taxes depreciation and amortization, or EBITDA, is less than or equal to 2.5, the applicable margin is 1.00% for base rate loans and 2.00% for LIBOR loans;

- where our leverage ratio is greater than 2.5 but less than or equal to 3.0, the applicable margin is 1.25% for base rate loans and 2.25% for LIBOR loans;

- where our leverage ratio is greater than 3.0 but less than or equal to 3.5, the applicable margin is 1.75% for base rate loans and 2.75% for LIBOR loans; and

- where our leverage ratio is greater than 3.5, the applicable margin is 2.25% for base rate loans and 3.25% for LIBOR loans.

The applicable margin for the term loan is 0.75% higher for both base rate loans and LIBOR loans.

The credit facility requires us to maintain a ratio of funded debt to

EBITDA of not more than 4.0 to 1.0, reducing to 3.5 to 1.0 on June 30, 2005, and an interest coverage ratio of not less than 3.0 to 1.0. In addition, we will be required to prepay the term loan with the net proceeds of any asset sales or issuances of debt. With respect to any issuances of equity, we will be required to repay the term loan from the proceeds of such issuances to the extent our ratio of funded debt to EBITDA exceeds 3.5 to 1.0. We are required to pay down $560,000 in principal on the outstanding balance of the term loan quarterly. Any prepayments of principal with proceeds from asset or equity sales that it makes will be credited pro rata against this repayment obligation.

The credit agreement contains covenants customary for loans of this size, including restrictions on incurring additional debt and making material acquisitions, and a prohibition on paying distributions to our unitholders if an event of default occurs. The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of our representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our general partner.

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RECENT DEVELOPMENTS

On March 8, 2005, we entered into an agreement with LG PL, LLC, a Texas limited liability company, and La Grange Acquisition, L.P., a Texas limited partnership, both subsidiaries of Energy Transfer Partners, L.P. (NYSE: ETP), to acquire all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd., a Texas limited partnership. ETC Oklahoma Pipeline's principal assets include more than 315 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma, a natural gas processing facility in Elk City, Oklahoma and a gas treatment plant in Prentiss, Oklahoma. The total consideration will be approximately $190 million in cash. The purchase price is subject to post-closing adjustment based on gas imbalances, certain prepaid costs and expenses and capital expenditures, and title defects, if any. Consummation of the acquisition is conditioned on the receipt of various approvals, including Hart-Scott-Rodino Act approval or early termination of the application waiting period, and other customary closing conditions.

We have received a commitment from Wachovia Bank, National Association and Bank of America, N.A. to arrange the syndication of a $270 million loan facility. The facility will be comprised of a $225 million 5-year revolving loan and a $45 million 5-year term loan. Up to $10.0 million of the facility may be used for standby letters of credit. Borrowings under the facility will be secured by a lien on and security interest in all of our property and that of our subsidiaries and by the guaranty of each of our subsidiaries. The loan proceeds will be used to refinance our existing $135 million facility and to finance the acquisition of ETC Oklahoma Pipeline.

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COMPETITION

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

As our omnibus agreement with Atlas America generally requires it to connect wells it operates to our system, we do not expect any direct competition in connecting wells drilled and operated by Atlas America in the future. In addition, we occasionally connect wells operated by third parties. During 2004, we connected no such wells.

During 2004, we encountered competition in acquiring gas gathering systems owned by third parties. In several instances we submitted bids in auction situations and in direct negotiations for the acquisition of existing gas gathering systems. Except for our bid for Spectrum, in each case we were either outbid by others or were unwilling to meet the sellers' expectations and, as a result, were unsuccessful in acquiring those systems. In the future, we expect to encounter equal if not greater competition for gathering system acquisitions because, as gas prices increase, the economic attractiveness of owning gathering systems increases.

Mid-Continent. In its southern Oklahoma and north Texas service area, APLMC competes for the acquisition of well connections with several other gathering/servicing operations. These operations include plants operated by Duke Energy Field Services, ONEOK Field Services and Enogex. We believe that the principal factors upon which competition for new well connections is based are:

- the price received by an operator 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.

We believe that our electric compressors operate more efficiently than the gas-operated compressors used by our competitors. As a result, we believe that we can operate as or more cost-effectively than our competitors. We also believe that our relationships with operators connected to our system are good. However, if APLMC cannot compete successfully, it may be unable to obtain new well connections and, possibly, could lose wells already connected to its system. [See "Risk Factors--APLMC's success depends upon its ability to continually find and contract for new sources of natural gas supply."]

REGULATION

Federal Regulation. Under the Natural Gas Act, the Federal Energy Regulatory Commission regulates various aspects of the operations of any "natural gas company," including the transportation of natural gas, rates and charges, construction of new facilities, extension or abandonment of services and facilities, the acquisition and disposition of facilities, reporting requirements, and similar matters. However, the Natural Gas Act definition of a "natural gas company" requires that the company be engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of natural gas for resale. Since we believe that each of our individual gathering systems perform primarily gathering functions, we believe that we are not subject to regulation under the Natural Gas Act. If we were determined to be a natural gas company, our operations would become regulated under the Natural Gas Act. We believe the expenses associated with seeking certificates of authority for construction, service and abandonment, establishing rates and a tariff for our gas gathering activities, and meeting the detailed regulatory accounting and reporting requirements under the Natural Gas Act would substantially increase our operating costs and would adversely affect our profitability, thereby reducing our ability to make distributions to unitholders.

State Regulation. Our operations are subject to regulation by the Public Utility Commission of Ohio, the New York Public Service Commission and the Pennsylvania Public Utilities Commission. APLMC's operations are subject to regulation by the Oklahoma Corporation Commission and the Texas Railroad Commission.

In Ohio, a producer or gatherer of natural gas may file an application seeking exemption from regulation as a public utility. We have been granted an exemption by the Public Utility Commission of Ohio for our Ohio facilities. The New York Public Service Commission imposes traditional public utility regulation on the transportation of natural gas by companies subject to its regulation. This regulation includes rates, services and siting authority for the construction of certain facilities. Our gas gathering operations currently are not subject to regulation by the New York Public Service Commission. Our operations in Pennsylvania currently are not subject to the Pennsylvania Public Utility Commission's regulatory authority since they do not provide service to the public generally and, accordingly, do not constitute the operation of a public utility. In the event the New York and Pennsylvania authorities seek to regulate our operations, we believe that our operating costs could increase and our transportation fees could be adversely affected, thereby reducing our net revenues and ability to make distributions to unitholders.

APLMC is subject to regulation by the Oklahoma Corporation Commission and the Texas Railroad Commission. The state of Oklahoma has adopted a complaint-based statute that allows the Oklahoma Corporation Commission 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 complaint has been made against APLMC to date in either Oklahoma or Texas.

Environmental and Safety Regulation. Under the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Toxic Substances Control Act, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, the Clean Water Act and other federal and state laws relating to discharges of materials into the environment or otherwise protective of the environment, owners and operators of natural gas pipelines and associated storage and processing facilities can be liable, sometimes on a strict, joint and several basis, for fines, penalties investigatory and remedial costs, and compliance costs including capital expenditures with respect to pollution caused by the pipelines and associated facilities. Moreover, the owners' and operators' liability can extend to pollution costs that arose from activities or incidents that occurred prior to such owners' or operators' acquisition of the pipelines and associated facilities, even in circumstances where the current owner or operator did not cause or contribute to the pollution.

We own, lease or operate properties that in the past have been subject to pipeline gathering and/or oil and gas processing activities. Although we have used operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under these properties or on or under other locations where such materials have been taken for disposal. A number of these properties have been operated by previous owners or operators whose environmental activities were not under our control. These properties and the hydrocarbons and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed hydrocarbons, hazardous substances, or wastes or property contamination, or to perform investigatory and remedial actions to prevent future contamination.

Natural gas pipelines are also subject to safety regulation, administered by state regulators, under the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Act of 1992 which, among other things, dictate the type of pipeline, quality of pipeline, depth, methods of welding and other construction-related standards and subjects pipelines to regular inspections. The state public utility regulators in our service areas have either adopted the federal standards or promulgated their own safety requirements consistent with federal regulations. Although we believe that our gathering systems comply in all material respects with applicable environmental and safety regulations, risks of substantial costs and liabilities are inherent in pipeline operations, and we cannot assure you that we will not incur these costs and liabilities. Moreover, it is possible that other developments, such as increasingly rigorous environmental laws, regulations and enforcement policies, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are also subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state statutes. We believe that our operations comply in all material respects with OSHA requirements, including general industry standards, record keeping, hazard communication requirements and monitoring of occupational exposure and other regulated substances.

We have not expended and do not anticipate that we will be required in the near future to expend, amounts that are material in relation to our revenues by reason of environmental and safety laws. However, we cannot predict legislative or regulatory developments or the costs of compliance with those developments. In general, however, we anticipate that new laws, regulations or policies will increase our operating costs and impose additional capital expenditure requirements on us.

TAX TREATMENT OF PUBLICLY TRADED PARTNERSHIPS UNDER THE INTERNAL REVENUE CODE

The Internal Revenue Code of 1986, as amended, imposes certain limitations on the current deductibility of losses attributable to investments in publicly traded partnerships and treats certain publicly traded partnerships as corporations for federal income tax purposes. The following discussion briefly describes certain aspects of the Code that apply to individuals who are citizens or residents of the United States without commenting on all of the federal income tax matters affecting us or the holders of our units, and is qualified in its entirety by reference to the Code. UNITHOLDERS ARE URGED TO CONSULT THEIR OWN TAX ADVISOR ABOUT THE FEDERAL, STATE, LOCAL AND FOREIGN TAX CONSEQUENCES TO THEM OF AN INVESTMENT IN US.

Characterization for Tax Purposes. The Code treats a publicly traded partnership as a corporation for federal income tax purposes unless, for each taxable year, 90% or more of its gross income consists of qualifying income. Qualifying income includes interest, dividends, real property rents, gains from the sale or disposition of real property, income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber), and gain from the sale or disposition of capital assets that produce such income. Because we are engaged primarily in the natural gas pipeline transportation business, we believe that 90% or more of our gross income has been qualifying income. If this continues to be true and no subsequent legislation amends that provision, we will continue to be classified as a partnership and not as a corporation for federal income tax purposes.

Passive Activity Loss Rules. The Code provides that an individual, estate, trust, or personal service corporation generally may not deduct losses from passive activities, to the extent they exceed income from all such passive activities, against other (active) income. Income that may not be offset by passive activity losses includes not only salary and active business income, but also portfolio income such as interest, dividends or royalties or gain from the sale of property that produces portfolio income. Credits from passive activities are also limited to the tax attributable to any income from passive activities. The passive activity loss rules are applied after other applicable limitations on deductions, such as the at-risk rules and basis limitations.

Under the Code, net income from publicly traded partnerships is not treated as passive income for purposes of the passive lose rule, but is treated as non-passive income. Net losses and credits attributable to an interest in a publicly traded partnership may not be used to offset a partner's other income. Thus, a unitholder's proportionate share of our net losses may be used to offset only partnership net income from our trade or business in succeeding taxable years or, upon a complete disposition of a unitholder's interest in us to an unrelated person in a fully taxable transaction, may be used to offset gain recognized upon the disposition, and then against all other income of the unitholder. In effect, net losses are suspended and carried forward indefinitely until utilized to offset net income of the partnership from its trade or business or allowed upon the complete disposition to an unrelated person in a fully taxable transaction of the unitholder's interest in the partnership. A unitholder's share of partnership net income may not be offset by passive activity losses generated by other passive activities. In addition, a unitholder's proportionate share of our portfolio income, including portfolio income arising from the investment of our working capital, is not treated as income from a passive activity and may not be offset by such unitholder's share of net losses of the partnership.

Deductibility of Interest Expense. The Code generally provides that investment interest expense is deductible only to the extent of a non-corporate taxpayer's net investment income. In general, net investment income for purposes of this limitation includes gross income from property held for investment, gain attributable to the disposition of the property held for investment (except for net capital gains for which the taxpayer has elected to be taxed at special capital gains rates) and portfolio income (determined pursuant to the passive lose rules) reduced by certain expenses (other than interest) which are directly connected with the production of such income. Property subject to the passive loss rules is not treated as property held for investment. However, the IRS has issued a Notice which provides that net income from a publicly traded partnership (not otherwise treated as a corporation) may be included in net investment income for purposes of the limitation on the deductibility of investment interest. A unitholder's investment income attributable to its interest in us will include both its allocable share of our portfolio income and trade or business income. A unitholder's investment interest expense will include its allocable share of our interest expense attributable to portfolio investments.

Unrelated Business Taxable Income. Certain entities otherwise exempt from federal income taxes (such as individual retirement accounts, pension plans and charitable organizations) are nevertheless subject to federal income tax on net unrelated business taxable income and each such entity must file a tax return for each year in which it has more than $1,000 of gross income from unrelated business activities. We believe that substantially all of our gross income will be treated as derived from an unrelated trade or business and taxable to such entities. The tax-exempt entity's share of our deductions directly connected with carrying on such unrelated trade or business are allowed in computing the entity's taxable unrelated business income.

State Tax Treatment. During 2004, we owned property or conducted business in the states of Pennsylvania, New York, Oklahoma, Ohio and Texas. A unitholder is required to file state income tax returns and to pay applicable state income taxes in the states and may be subject to penalties for failure to comply with such requirements. None of these states have required that we withhold a percentage of income attributable to our operations within the state for unitholders who are non-residents of the state. In the event that one or more of them do require withholding in the future, (which may be greater or less than a particular unitholder's income tax liability to the state), such withholding would generally not relieve the non-resident unitholder from the obligation to file a state income tax return.

Depreciation. Upon our formation in 2000, we elected fifteen-year 150% declining-balance depreciation for tax purposes. Unitholders, however, will continue to offset partnership income with individual unitholder depreciation pursuant to our Section 754 election. Each unitholder's tax situation will differ depending upon the price paid and when units were purchased. Furthermore, sale of units will result in a portion of gain (if any) being taxable as ordinary income through recapture of previous deductions for depreciation.

EMPLOYEES

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operations. In general, employees of Atlas America and its parent company, Resource America, Inc., manage the gathering systems and operate our business. Affiliates of our general partner will conduct business and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition between us, our general partner and affiliates of our general partner for the time and effort of the officers and employees who provide services to our general partner. The officers of our general partner who provide services to us are not required to work full time on our affairs. These officers may devote significant time to the affairs of our general partner's affiliates and be compensated by these affiliates for the services rendered to them. There may be significant conflicts between us and affiliates of our general partner regarding the availability of these officers to manage us.

AVAILABLE INFORMATION

We make our periodic reports under the Securities Exchange Act of 1934, including our annual report on Form 10-K, our quarterly reports on Form 10-Q and our current reports on Form 8-K, available through our website at www.atlaspipelinepartners.com. To view these reports, click on "Investor Relations," then "SEC Filings." You may also receive, without charge, a paper copy of any such filings by request to us at 311 Rouser Road, Moon Township, Pennsylvania 15108, tel. no. (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 SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The Public Reference Room may be contacted at 1-800- SEC-0330 for further information.

RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks we encounter are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks actually occurs, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and investors may lose some or all of their investment.

General

Interest rate increases will increase our interest costs. See Item 7A, "Quantitative and Qualitative Disclosures about Market Risk." This could have material adverse effects on us, including reduction of our net income.

Our cash distributions are not assured and may fluctuate with our performance.

The amounts of cash that we generate may not be sufficient to pay the minimum quarterly distributions established in our partnership agreement or any other level of distributions. The actual amounts of cash we generate will depend upon numerous factors relating to our business which may be beyond our control, including:

- the demand for and price of natural gas and NGLs;

- the volume of natural gas we transport;

- the availability of local, intrastate and interstate transportation systems;

- continued development of wells for connection to our gathering systems;

- the expenses we incur in providing our gathering services;

- the cost of acquisitions and capital improvements;

- our issuance of equity securities;

- required principal and interest payments on our debt;

- fluctuations in working capital;

- prevailing economic conditions;

- fuel conservation measures;

- alternate fuel requirements;

- government regulation and taxation; and

- technical advances in fuel economy and energy generation devices.

Our ability to make cash distributions depends primarily on our cash flow. Cash distributions do not depend directly on our profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when we record losses and may not be made during periods when we record profits.

The failure of Atlas America to perform its obligations under the natural gas gathering agreements may adversely affect our revenues.

A majority of our Appalachian revenues currently consist of the fees we receive under the master natural gas gathering agreement and other transportation agreements we have with Atlas America and its affiliates. While Atlas America receives gathering fees from the well owners, it is contractually obligated to pay our fees even if the gathering fees paid to it by well owners are less than the fees it must pay us. Our cash flow could be materially adversely affected if Atlas America failed to discharge its obligations to us.

The amount of natural gas we transport will decline over time unless new wells are connected to our gathering systems.

Production of natural gas from a well generally declines over time until the well can no longer economically produce natural gas and is plugged and abandoned. Failure to connect new wells to our gathering systems could, therefore, result in the amount of natural gas we transport reducing substantially over time and could, upon exhaustion of the current wells, cause us to abandon one or more of our gathering systems and, possibly, cease operations. As a consequence, our revenues and, thus, our ability to make distributions to unitholders would be materially adversely affected.

We entered into the omnibus agreement with Atlas America to, among other things, increase the number of natural gas wells connected to our gathering systems. However, well connections resulting from that agreement depend principally upon the success of Atlas America in sponsoring drilling investment partnerships and completing wells for these partnerships in areas where our gathering systems are located. If Atlas America cannot or does not continue to organize these partnerships, if the amount of money raised by these partnerships decreases, or if the number of wells actually drilled and completed as commercial producing wells decreases, our revenues and ability to make cash distributions will be materially adversely affected.

APLMCs success depends upon its ability to continually find and contract for new sources of natural gas supply.

As with our Appalachian Basin operations, in order for APLMC to maintain or increase throughput levels on its gathering systems and at its processing plant, it must continually contract for new natural gas supplies. The primary factors affecting APLMC's ability to connect new supplies of natural gas to its gathering systems include its success in contracting for existing wells that are not committed to other systems and the level of drilling activity near its gathering systems. Unlike our Appalachian Basin operations, none of the drillers or operators in APLMC's service area are our affiliates.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over the level of drilling activity in APLMC's operating areas, the amount of reserves underlying wells that connect to its system and the rate at which production from a well will decline, sometimes referred to as the "decline rate." In addition, APLMC 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.

The amount of natural gas we transport may be reduced if the public utility pipelines to which we deliver gas cannot or will not accept the gas.

Our gathering systems principally serve as intermediate transportation facilities between sales lines from wells connected to our systems and the public utility pipelines to which we deliver natural gas. If one or more of these public utility pipelines has service interruptions, capacity limitations or otherwise does not accept the natural gas we transport, and we cannot arrange for delivery to other public utility pipelines, local distribution companies or end users, the amount of natural gas we transport may be reduced. Since our revenues depend upon the volumes of natural gas we transport, this could result in a material reduction in our revenues.

Our Mid-Continent operations depend on certain key producers for their supply of natural gas; the loss of any of these key producers could reduce our revenues.

During 2003, ChevronTexaco, Inc., Chesapeake Operating, Inc. and Mack Energy Co. supplied Spectrum with approximately 40% of its natural gas supply. During 2004 those producers, together with Zinke & Trumbo, Inc. supplied Spectrum with approximately 44% of its natural gas supply. If these producers reduce the volumes of natural gas that they supply to us, our revenues would be reduced unless we obtain comparable supplies of natural gas from other producers.

APLMC is exposed to the credit risk of its customers and an increase in nonpayment could lead to material losses.

During the years ended December 31, 2004 and 2003, ONEOK Energy Marketing and Trading accounted for approximately 31% and 85%, respectively of APLMC's residue natural gas sales from APLMC's Velma Plant and Tenaska Marketing Ventures accounted for approximately 12% and 15%, respectively of such sales. Koch Hydrocarbons, L.P. accounted for all of Spectrum's NGL sales. Should any of these customers fail to fulfill their payment obligations, become insolvent or file a petition in bankruptcy, we would incur material losses.

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We have no previous experience either in APLMC's service area or in operating a natural gas processing plant.

APLMC's pipelines are located in southern Oklahoma and northern Texas, areas in which we have had no previous operations. In addition, APLMC operates a natural gas processing plant, a business with which we have had no previous operating experience. As a result, we will depend upon the experience, knowledge and business relationships that have been developed by APLMC's senior management, who are employees of our general partner, to operate APLMC successfully. The loss of the services of one or more members of APLMC's senior management and, in particular, Robert R. Firth, APLMC's President and David D. Hall, APLMC's Chief Financial Officer, could limit APLMC's growth or its ability to maintain its current level of operations.

We may be unable to successfully integrate APLMC's operations with our operations and to realize all of the anticipated benefits of the acquisition.

We acquired APLMC in July 2004 and are currently in the process of integrating its operations with ours. The integration of two companies that previously have operated independently can be a complex, costly and time-consuming process. The difficulties of combining the companies include, among other things:

- operating a significantly larger combined company;

- the necessity of coordinating geographically disparate organizations, systems and facilities;

- integrating personnel with diverse business backgrounds and organizational cultures; and

- consolidating corporate and administrative functions.

Combining the companies may be made particularly difficult by the large size of APLMC as compared to us and the geographic separation of its operations and our Appalachian Basin operations. The process of combining the companies could cause an interruption in our business and, possibly, the loss of key personnel. The diversion of management's attention and any delays or difficulties encountered in connection with the integration of the two companies could harm our business, results of operations, financial condition or prospects.

Governmental regulation of our pipelines could increase our operating costs, decrease our revenues, or both.

Currently our gathering of natural gas from wells is exempt from regulation under the Natural Gas Act. However, the implementation of new laws or policies could subject us to regulation by the Federal Energy Regulatory Commission under the Natural Gas Act. We expect that any such regulation would increase our costs, decrease our revenues, or both.

Gas gathering operations are subject to regulation at the state level. Matters subject to regulation include rates, service and safety. We have been granted an exemption from regulation as a public utility in Ohio. Presently, our rates are not regulated in New York and Pennsylvania. The state of Oklahoma has adopted a complaint-based statute that allows the Oklahoma Corporation Commission 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. The gathering fees Spectrum charges are deemed just and reasonable under Oklahoma and Texas law unless challenged by a complaint. Should a complaint be filed or regulation by either of the commissions become more active, our revenues could decrease.

Changes in state regulations, or our status under these regulations that subject us to further regulation, could increase our operating costs or require material capital expenditures.

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

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

We are also subject to the requirements of OSHA, and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our costs of compliance. In general, we expect that new regulations would increase our operating costs and, possibly, require us to obtain additional capital to pay for improvements or other compliance action necessitated by those regulations.

We may not be able to fully execute our growth strategy.

Our strategy contemplates substantial growth through both the acquisition of other gathering systems and the development of our existing system. Typically, we have paid for system development in cash and have made acquisitions either for cash or a combination of cash and common units. As a result, limitations on our access to capital or on the market for our common units will impair our ability to execute our growth strategy. In addition, our strategy of growth through acquisitions involves numerous risks, including:

- we may not be able to identify suitable acquisition candidates;
- we may not be able to make acquisitions on economically acceptable terms;
- our costs in seeking to make acquisitions may be material, even if we cannot complete any acquisition we have pursued;
- irrespective of estimates at the time we make an acquisition, the acquisition may prove to be dilutive to earnings and operating surplus; and
- we may encounter difficulties in integrating operations and systems.

A decline in natural gas prices could adversely affect our revenues.

Our gathering fees are generally equal to a percentage of either the gross or weighted average sales price of the natural gas we transport, although in some cases we receive a flat fee per mcf of gas transported. Our income therefore depends upon the prices at which the natural gas we transport is sold. Historically, the price of natural gas has been volatile; as a result, our income may vary widely from period to period.

Gathering system operations are subject to operational hazards and unforeseen interruptions.

The operations of our gathering systems are subject to hazards and unforeseen interruptions, including natural disasters, adverse weather, accidents or other events beyond our control. A casualty occurrence might result in injury and extensive property or environmental damage. Our insurance coverage may not be sufficient for any casualty loss we may incur.

ITEM 2. DESCRIPTION OF PROPERTIES

As of December 31, 2004 our principal facilities in Appalachia include approximately 1,440 miles of 2 to 12 inch diameter pipeline and 56 compressors, of which four are leased. Our principal facilities in the Mid-Continent area consist of a natural gas processing plant, approximately 1,900 miles of active and inactive 2-to-42 inch diameter pipeline, and 18 compressors, of which seven are leased. Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property under long-term leases.

PIPELINE CHARACTERISTICS

We set forth in the following table the volumes of the natural gas we transported, in mcfs, in the years ended December 31, 2004, 2003 and 2002.

For the years December	
2004	2003

New York systems	423,400	449,8
Ohio systems	4,684,600	5,060,2
Oklahoma systems	9,055,600	
Pennsylvania systems	14,415,600	13,642,3
Texas systems	482,900	
	29,062,100	19,152,3

Of the approximately 4,500 wells currently connected to our Appalachian gathering systems, approximately 4,400 are owned by Atlas America or its affiliates or by investment partnerships managed or operated by Atlas America or its affiliates, with the remainder being owned or managed by third parties. We have agreements with Atlas America and its affiliates relating to the connection of future wells owned or controlled by them to our gathering systems and the transportation fees we will charge. These wells are the principal producers of gas transported by our gathering systems and we anticipate that wells controlled by Atlas America will continue in the future to be the principal producers into our gathering systems. As of December 31, 2004, Atlas America and its affiliates controlled leases on developed properties in the operational area of our gathering systems totaling approximately 196,800 gross acres. In addition, Atlas America and its affiliates control leases on approximately 226,706 undeveloped gross acres of land. During the year ended December 31, 2004, Atlas America and its affiliates drilled and connected 335 wells to our gathering systems as compared to 270 and 214 wells during the years ended December 31, 2003 and 2002, respectively.

Our Appalachian gathering systems are generally constructed with 2, 4, 6, 8 and 12 inch cathodically protected and wrapped steel pipe and are generally buried 36 inches below the ground. Pipelines constructed in this manner typically are expected to last at least 50 years from the date of construction. For the years ended December 31, 2004, 2003 and 2002, the cost of operating the gathering systems, excluding depreciation, was approximately $2.3 million, $2.4 million and $2.1 million, respectively. We do not believe that there are any significant geographic limitations upon our ability to expand in the areas served by our gathering systems.

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APLMC has a Gas Plant and Gathering System located in Velma, Oklahoma. The Velma Gas Plant has inlet gas processing and treating capacity of 100 MMCFD (100 million cubic feet per day) and residue gas compression capacity of approximately 58 MMCFD. The plant receives natural gas from the upstream Velma Gathering System and delivers residue gas to two pipelines at the tailgate of the plant and NGL liquids to a liquids pipeline.

The Velma Gas Plant is a twin-expander cryogenic facility with natural gas throughput capacity of approximately 100MMCFD. Key components of the plant are: an amine treating system (for C02 and H2S); an acid gas disposal well; a 12,000 HP electric inlet compression, a 5,000 HP residue electric compression. The Velma Gathering System is comprised of approximately 1,100 miles of active and 760 miles of inactive pipeline ranging in size from 2 inches to 42 inches in diameter and 18 field booster sites providing 14,417 horsepower. It currently gathers 60 MMCFD of natural gas, which is delivered to the Velma Gas Plant, from approximately 580 receipt points owned by producers and other gatherers.

Our revenues are determined primarily by the amount of natural gas flowing through our gathering systems and the price received for this natural gas. Our ability to increase the flow of natural gas through our gathering systems and to offset the natural decline of the production already connected to our gathering systems will be determined primarily by our ability to connect new wells to our gathering systems and to acquire additional gathering assets.

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections, although these imperfections have not interfered, and our general partner does not expect that they will materially interfere with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants. In a few instances, our rights-of-way are revocable at the election of the land owners. In some cases, not all of the owners named in the appropriate land records have joined in the right-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary, although in some instances these permits are revocable at the election of the grantor. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election.

Certain of our rights to lay and maintain pipelines are derived from recorded gas well leases, which wells 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.

We rent 8,000 square feet of office space in Tulsa, Oklahoma through July 2005 for our Mid-Continent operations.

ITEM 3. LEGAL PROCEEDINGS

On March 9, 2004, the Oklahoma Tax Commission ("OTC") filed a petition against Spectrum alleging that Spectrum underpaid gross production taxes beginning in June 2000. The OTC is seeking a settlement of $5.0 million plus interest and penalties. We plan on defending ourselves vigorously. In addition, under the terms of the Spectrum purchase agreement, $14.0 million has been placed in escrow to cover the costs of any adverse settlement resulting from the petition and other indemnification obligations of the purchase agreement.

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Settlement of Alaska Pipeline Company Arbitration. In September 2003, we entered into an agreement with SEMCO Energy, Inc. to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, we 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 us a notice purporting to terminate the transaction. We pursued our remedies under the acquisition agreement. In connection with the acquisition, subsequent termination, and settlement of the legal action, we incurred costs of approximately $4.0 million in the year ended December 31, 2004. On December 30, 2004, we entered into a settlement agreement with SEMCO settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline Company to us and SEMCO paid us $5.5 million.

We are not, nor are any of our gathering systems, subject to any other pending legal proceedings.

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

No matters were submitted to a vote of the common unitholders during the fourth quarter of the year ended December 31, 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED UNITHOLDER MATTERS

Our common units are listed on the New York Stock Exchange under the symbol "APL." As of December 31, 2004, 73 holders of record held our common units. In connection with our initial public offering, we also issued 1,641,026 subordinated units, discussed below, all of which are held by our general partner. There is no established public trading market for the subordinated units.

The following table sets forth the range of high and low sales prices of our common units and distributions per unit on our common and subordinated units for the last two years.

	High	Lo
FISCAL 2004		
Fourth Quarter..	$ 42.90	$ 3
Third Quarter...	$ 38.32	$ 3
Second Quarter..	$ 40.03	$ 3
First Quarter...	$ 41.50	$ 3
FISCAL 2003		
Fourth Quarter..	$ 42.50	$ 3
Third Quarter...	$ 36.00	$ 2
Second Quarter..	$ 31.70	$ 2
First Quarter...	$ 28.96	$ 2

Our partnership agreement generally requires us to distribute available cash 98% to the limited partners and 2% to our general partner except for our general partner's incentive distribution rights. These rights require distributions of increased percentages of available cash to the general partner as distributions to limited partners exceed specified minimums, as follows:

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Minimum Distributions Per Unit Per Quarter	Percent of Available Cash in Excess of Minimum Allocated to the General Partner
$ .42	15%
$ .52	25%
$ .60	50%

Available cash generally means for any of our quarters, all cash on hand at the end of the quarter less cash reserves that our general partner determines are appropriate to provide for our operating costs, including potential acquisitions, and to provide funds for distributions to the partners for any one or more of the next four quarters.

Our partnership agreement allocates distributions to limited partners in accordance with their relative number of units except that, during the subordination period, distributions to subordinated units are subordinated to the receipt by the common units of a minimum quarterly distribution of $.42 per common unit, plus any unpaid minimum quarterly distribution amounts from prior periods. The subordination period terminated on January 1, 2005. Upon expiration of the subordination period, the subordinated units converted into common units on a one-for-one basis, and will now participate pro rata with the other common units in distributions of our available cash.

We make distributions of available cash to unitholders regardless of whether the amount distributed is less than the minimum quarterly distribution.

For information concerning units authorized for issuance under our long-term incentive plan, see Notes 8 and 15 of our Notes to Consolidated Financial Statements.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data should be read together with our consolidated financial statements, the notes to our consolidated financial statements and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 in this report. We have derived the selected financial data set forth below for each of the years ended December 31, 2004, 2003 and 2002 and at December 31, 2004 and 2003 from our consolidated financial statements appearing elsewhere in this report, which have been audited by Grant Thornton LLP, independent accountants. We derived the financial data as of December 31, 2002, 2001 and 2000 and for the years ended December 31, 2001 and 2000 from our financial statements, which were audited by Grant Thornton LLP, and are not included in this report. The financial data for the period ended December 31, 2000 is for the period beginning with the inception of our operations on January 28, 2000 through December 31, 2000; and, accordingly, we deem January 28, 2000 to be the commencement of our operations and we refer to the period from that date through December 31, 2000 as the year ended December 31, 2000.

	For the years ended Dece		
	2004(1)	2003	2002
	(in thousands, except average transportati		
INCOME STATEMENT DATA:			
Revenues...	$ 91,291	$ 15,749	$10,667
Total operating and general and administrative expenses.........................	$ 67,642	$ 4,082	$ 3,544
Depreciation and amortization......................	$ 4,471	$ 1,770	$ 1,475
Net income...	$ 18,334	$ 9,639	$ 5,398
Average gross margin rate per Mcf (Mid-Continent)...	$ 1.41	$ -	$ -
Average transportation rate per Mcf (Appalachia)....	$ .96	$ .82	$ .58

Net income per limited partner unit - basic and diluted	$ 2.60	$ 2.17	$ 1.54

	At December 31,		
	2004(1)	2003	2002
	(in thousands, except per		
BALANCE SHEET DATA:			
Total assets	$ 216,785	$ 49,512	$28,515
Debt	$ 54,452	$ -	$ 6,500
Common unitholders' capital	$ 135,759	$ 43,551	$19,164
Subordinated unitholder's capital	2	354	684
General partner's capital (deficit)	2,261	340	(161)
Accumulated other comprehensive loss	(1,318)	-	-
Total partners' capital	$ 136,704	$ 44,245	$19,687
Distributions declared per common unit	$ 2.67	$ 2.38	$ 2.14

	For the years ended Dece		
	2004	2003	2002
			(in thousands)
OTHER FINANCIAL DATA:			
Net cash provided by operating activities	$ 25,593	$ 13,702	$ 8,138
Net cash used in investing activities	$(151,797)	$ (9,154)	$(5,231)
Net cash provided by (used in) financing activities.	$ 129,340	$ 8,671	$(3,211)

(1) Includes the acquisition of Spectrum on July 16, 2004, representing five and one-half months operations in the year ended December 31, 2004 (See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.)

EBITDA means income before net interest expense, income taxes and depreciation and amortization and other non-cash items such as compensation expenses associated with unit issuances to employees of the general partner and directors. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution. Our method of computing EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA may be computed differently by us in different contexts (i.e., public reporting versus computation under financing agreements).

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Certain items excluded from EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and its tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA because

EBITDA provides investors and management with additional information as to our ability to pay our fixed charges and is presented solely as a supplemental financial measure. EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as an indicator of our operating performance or liquidity. The table below shows our EBITDA and reconciles it to our net income.

	For the years ended December 31,			
	2004	2003	2002	2001
	(in thousands)			
INCOME DATA:				
Net income	$18,334	$ 9,639	$5,398	$ 8,556
Non-cash compensation expense	700	-	-	-
Interest expense	2,301	258	250	176
Depreciation and amortization	4,471	1,770	1,475	1,356
EBITDA	$25,806	$11,667	$7,123	$10,088

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

FORWARD-LOOKING STATEMENTS

WHEN USED IN THIS FORM 10-K THE WORDS "BELIEVES" "ANTICIPATES" "EXPECTS" AND SIMILAR EXPRESSIONS ARE INTENDED TO IDENTIFY FORWARD-LOOKING STATEMENTS. SUCH STATEMENTS ARE SUBJECT TO CERTAIN RISKS AND UNCERTAINTIES MORE PARTICULARLY DESCRIBED IN ITEM 1 OF THIS REPORT, UNDER THE CAPTION "RISK FACTORS". THESE RISKS AND UNCERTAINTIES COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY. READERS ARE CAUTIONED NOT TO PLACE UNDUE RELIANCE ON THESE FORWARD-LOOKING STATEMENTS, WHICH SPEAK ONLY AS OF THE DATE HEREOF. WE UNDERTAKE NO OBLIGATION TO PUBLICLY RELEASE THE RESULTS OF ANY REVISIONS TO FORWARD-LOOKING STATEMENTS WHICH WE MAY MAKE TO REFLECT EVENTS OR CIRCUMSTANCES AFTER THE DATE OF THIS FORM 10-K OR TO REFLECT THE OCCURRENCE OF UNANTICIPATED EVENTS.

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

GENERAL

Our principal business objective is to generate income for distribution to our unitholders.

Our business is conducted in the midstream natural gas industry and we are active in the Appalachian and Mid-Continent areas of the United States, specifically, Pennsylvania, Ohio, New York, Oklahoma and Texas.

In Appalachia, we gather approximately 53 million cubic feet of gas per day through our pipeline system from more than 5,200 wells for delivery to a variety of customers on major intra- or interstate pipeline systems and a limited number of direct end-users. This transported gas is primarily controlled by Atlas America, Inc., the parent company of our general partner.

Our Mid-Continent operations began in July 2004 upon our acquisition of Spectrum Field Services, Inc. In the Mid-Continent, we purchase approximately 56 million cubic feet of gas per day under more than 650 separate gas purchase contracts. This gas is then transported to our Velma, Oklahoma gas processing facility where the natural gas liquids, or NGLs, along with various impurities are removed. The remaining pipeline quality gas is then delivered into a major intrastate pipeline system where it is sold at market prices. The NGLs are similarly delivered into a separate major intrastate pipeline system where they are also sold for a price determined by the value of the actual components of that liquid stream, for example, ethane, butane, propane etc.

FEE ARRANGEMENTS:

In Appalachia, substantially all of the gas we transport is for Atlas America under a POP contract where we earn a fee equal to a percentage, generally 16% of the selling price of the gas subject, in most cases to a minimum of $.35 or $.40 per mcf. Since our inception in January 2000, our transportation fee has always exceeded this minimum. The balance of the Appalachian gas we transport is for third party operators generally under fee contracts.

Our revenues in Mid-Continent are determined primarily by the fees APLMC earns from the following two types of arrangements:

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

Percent of Proceeds or POP Contracts: These contracts provide for us to retain a negotiated percentage of the residue natural gas and NGLs resulting from our gathering and processing operations with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value - we own a percentage of that commodity and are directly subject to its ultimate market value.

Unlike many of our competitors, we have no keep-whole contracts where the producer has the right to receive 100% of the thermal value of its produced raw natural gas based on the value of the processed and delivered pipeline quality residue natural gas. This type of contract exposes the processing company to frac-spread risk - the difference between the value of the NGL extracted from processing and the thermal value equivalent of the residue natural gas.

In the Mid-Continent, approximately 75% of our volumes and revenues are derived from POP contracts. The percentage of the proceeds that we retain is negotiated and can vary greatly depending on a variety of factors and circumstances.

Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. The number of active oil and gas rigs has increased in the past year, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during 2004. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We closely monitor the risks associated with these commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. The recognition in our Consolidated Statements of Income of the cumulative changes in the fair value of these hedge instruments reduced our results of operations by $259,000 in the year ended December 31, 2004. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk". The remaining term over which we are currently hedging our exposure to the variability of future cash flows is through the end of 2006.

SPECTRUM ACQUISITION

On July 16, 2004, we acquired Spectrum Field Services, Inc., which we refer to as Spectrum, Mid-Continent or APLMC, for approximately $142.4 million, including the payment of taxes due as a result of the transaction. This acquisition significantly increased our size and diversified the natural gas supply basins in which we operate and the natural gas midstream services we provide to our customers. We expect the Spectrum acquisition to be accretive to our cash distributions per common unit.

We financed the Spectrum acquisition, including approximately $4.2 million of transaction costs, as follows:

- o borrowing $100.0 million under the term loan portion of our new $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association;

- o using the $20.0 million of net proceeds received from the sale to Resource America, Inc. and Atlas America, Inc. of preferred units in our operating subsidiary Atlas Pipeline Operating Partnership, L.P.; and

- o using $22.4 million of the net proceeds from our April 2004 common unit offering.

In July 2004, we completed a public offering of 2,100,000 common units of limited partner interest whose net proceeds after underwriting discounts and commissions and costs were $67.5 million. We used a portion of the net proceeds of this offering to repay $40.0 million of the borrowings under our new credit facility and to repurchase the preferred units from Resource America and Atlas America.

The acquisition of Spectrum significantly changed our financial position and results of operations. At December 31, 2004, we had an available borrowing capacity $77.8 million. We intend to finance our growth with a combination of long-term debt and equity to maintain our financial flexibility to fund future opportunities.

SETTLEMENT OF ALASKA PIPELINE COMPANY ARBITRATION

In September 2003, we entered into an agreement with SEMCO Energy, Inc. to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, we 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. We pursued our remedies under the acquisition agreement. On December 30, 2004, we entered into a settlement agreement with SEMCO settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline Company to us and SEMCO paid us $5.5 million. In connection with the termination and settlement of the legal action, we incurred costs of approximately $1.4 million. In addition, we also incurred $2.6 million of costs associated with the acquisition of SEMCO. These proceeds and costs are shown as "Gain on arbitration settlement, net" on our consolidated statement of income for the year ended December 31, 2004.

RECENT DEVELOPMENTS

On March 8, 2005, we entered into an agreement with LG PL, LLC, a Texas limited liability company, and La Grange Acquisition, L.P., a Texas limited partnership, both subsidiaries of Energy Transfer Partners, L.P. (NYSE: ETP), to acquire all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd., a Texas limited partnership. ETC Oklahoma Pipeline's principal assets include more than 315 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma, a natural gas processing facility in Elk City, Oklahoma and a gas treatment plant in Prentiss, Oklahoma. The total consideration will be approximately $190 million in cash. The purchase price is subject to post-closing adjustment based on gas imbalances, certain prepaid costs and expenses and capital expenditures, and title defects, if any. Consummation of the acquisition is conditioned on the receipt of various approvals, including Hart-Scott-Rodino Act approval or early termination of the application waiting period, and other customary closing conditions.

We have received a commitment from Wachovia Bank, National Association and Bank of America, N.A. to arrange the syndication of a $270 million loan facility. The facility will be comprised of a $225 million 5-year revolving loan and a $45 million 5-year term loan. Up to $10.0 million of the facility may be used for standby letters of credit. Borrowings under the facility will be secured by a lien on and security interest in all of our property and that of our subsidiaries and by the guaranty of each of our subsidiaries. The loan proceeds will be used to refinance our existing $135 million facility and to finance the acquisition of ETC Oklahoma Pipeline.

RESULTS OF OPERATIONS

In the years ended December 31, 2004, 2003 and 2002, our principal revenues came from the operation of our pipeline gathering systems which transport, process and compress natural gas. Two variables which affect our transportation revenues are:

- the volumes of natural gas transported by us which, in turn, depend upon the number of wells connected to our gathering system, the amount of natural gas they produce, and the demand for that natural gas; and

- the transportation fees paid to us which, in turn, depend upon the price of the natural gas we transport, which itself are a function of the relevant supply and demand in the mid-Atlantic and northeastern areas of the United States.

We set forth the average volumes we transported, our average gross margin rate per mcf and average transportation rates per Mcf and revenues received by us for the periods indicated in the following table:

	For the years December 31 (Dollars in thousands, exce	
	2004	2003
Average daily throughput volumes in mcf (Mid-Continent).....	56,441	-
Average daily throughput volumes in mcf (Appalachia)........	53,343	52,472
Total average daily throughput volumes in mcf..............	109,784	52,472
Average gross margin rate per mcf (Mid-Continent)...........	$ 1.41	$ -
Average transportation rate per mcf (Appalachia)............	$ .96	$ .82
Total natural gas and liquids gross margin (Mid-Continent)(1)	$ 13,402	$ -
Total transportation and compression revenues (Appalachia)..	$ 18,800	$ 15,651

(1) Gross margin calculated as natural gas and liquids revenue less natural gas and liquids costs.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Revenues. Our natural gas and liquid revenues are associated with our acquisition of Spectrum on July 16, 2004. These revenues reflect five and one half months of operations in the current year. We anticipate that these revenues will increase in 2005.

Our transportation and compression revenues increased to $18.8 million in the year ended December 31, 2004 from $15.7 million in the year ended December 31, 2003. This increase of $3.1 million (20%) consisted of an increase in the average transportation rate paid to us ($2.8 million) and an increase in the volumes of natural gas we transported ($357,000).

Our transportation rate was $.96 per Mcf in the year ended December 31, 2004 as compared to $.82 per Mcf in the year ended December 31, 2003, an increase of $.14 per Mcf (17%). During the year ended December 31, 2004, natural gas prices increased significantly over the year ended December 31, 2003. Since our transportation rates are generally at fixed percentages of the sale prices of the natural gas we transport, the higher prices resulted in an increase in our average transportation rate.

Our average daily throughput volumes in Appalachia were 53,343 Mcfs in the year ended December 31, 2004 as compared to 52,472 Mcfs in the year ended December 31, 2003, an increase of 871 mcfs (2%). The increase in the average daily throughput volume resulted principally from volumes associated with new wells added to our pipeline system; we turned on-line 335 and 270 wells in the years ended December 31, 2004 and 2003, respectively. These increases were partially offset by the natural decline in production volumes from existing wells connected to our gathering systems.

Our gain on arbitration settlement, net is the result of a December 30, 2004 settlement agreement with SEMCO settling all issues and matters related to SEMCO's termination of the sale of Alaska Pipeline Company to us. SEMCO paid us $5.5 million, which is shown net of $1.4 million of arbitration costs and $2.6 million of acquisition costs.

Costs and Expenses. Our natural gas and NGL and plant operating expenses are associated with our acquisition of Spectrum on July 16, 2004. These expenses reflect five and one half months of operations in the current year. We anticipate that these expenses will increase in 2005.

Our transportation and compression expenses decreased to $2.3 million in the year ended December 31, 2004 as compared to $2.4 million in the year ended December 31, 2003, a decrease of $161,000 (7%). Our average cost per Mcf of transportation and compression decreased to $.12 in the year ended December 31, 2004 as compared to $.13 in the year ended December 31, 2003, a decrease of $.01 (8%). This decrease resulted primarily from a decrease in compressor expenses due to our purchase of several compressors in the year 2003 which we had previously leased.

Our general and administrative expenses increased to $4.6 million in the year ended December 31, 2004 as compared to $1.7 million in the year ended December 31, 2003, an increase of $2.9 million (180%). This increase includes the following:

- $1.1 million of general and administrative expenses associated with the operations of Spectrum which we acquired on July 16, 2004;

- $821,000 for the expensing of phantom units issued under our Long-Term Incentive Plan and the related distributions on those units;

- $473,000 in increased allocations of compensation and benefits from Atlas America and its affiliates due to an increase in management time spent on our acquisition and public offerings; and

- $349,000 from costs associated with the implementation of Sarbanes-Oxley and the preparation and filing of two tax returns for 2003. The filing of two tax returns was a result of our general partner's percentage interest in us being reduced below 50% as a result of our offering of common units in May 2003, requiring a change in our tax year-end from September 30th to December 31st which necessitated the filing of an additional short year tax return. This expense is non-recurring.

Our depreciation and amortization expense increased to $4.5 million in the year ended December 31, 2004 as compared to $1.8 million in the year ended December 31, 2003, an increase of $2.7 million (153%). This increase resulted from depreciation associated with the acquisition of Spectrum ($2.4 million), and our increased asset base associated with pipeline extensions and compressor upgrades. We anticipate that our depreciation expense will increase in 2005 as a result of a full year of depreciation associated with APLMC and depreciation associated with our pipeline extensions and compressor upgrades.

Our interest expense increased to $2.3 million in the year ended December 31, 2004 as compared to $258,000 in the year ended December 31, 2003.

This increase of $2.0 million resulted from increased borrowings in the year ended December 31, 2004 as compared to the year ended December 31, 2003. In July 2004, we borrowed $100.0 million to partially fund our acquisition of Spectrum. Subsequently, in July 2004, we repaid $40.0 million of these borrowings upon the completion of our public offering. In December 2004, we borrowed $10.0 million on our revolver facility in order to repay $15.0 million of our term-loan borrowings. Our interest expense in the year ended December 31, 2003 consisted of fees on our outstanding borrowings, commitment fees on amounts not drawn on our credit facility, and amortization of our debt issuance costs.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Revenues. Our transportation and compression revenues increased to $15.7 million in the year ended December 31, 2003 from $10.7 million in the year ended December 31, 2002. This increase of $5.0 million (47%) resulted from an increase in the average transportation rate paid to us ($4.4 million) and an increase in the volumes of natural gas we transported ($629,000).

Our transportation rate was $.82 per Mcf in the year ended December 31, 2003 as compared to $.58 per Mcf in the year ended December 31, 2002, an increase of $.24 per Mcf (41%). During the year ended December 31, 2003, natural gas prices increased significantly over the year ended December 31, 2002. Since our transportation rates are generally at fixed percentages of the sale prices of the natural gas we transport, the higher prices resulted in an increase in our average transportation rate.

Our average daily throughput volumes were 52,472 Mcfs in the year ended December 31, 2003 as compared to 50,363 Mcfs in the year ended December 31, 2002, an increase of 2,109 Mcfs (4%). The increase in the average daily throughput volume resulted principally from volumes associated with new wells added to our pipeline system; we turned on-line 270 and 214 wells in the years ended December 31, 2003 and 2002, respectively. These increases were partially offset by the natural decline in production volumes from existing wells connected to our gathering systems.

Costs and Expenses. Our transportation and compression expenses increased to $2.4 million in the year ended December 31, 2003 as compared to $2.1 million in the year ended December 31, 2002, an increase of $358,900 (17%). Our average cost per Mcf of transportation and compression increased to $.13 in the year ended December 31, 2003 as compared to $.11 in the year ended December 31, 2002, an increase of $.02 (18%). This increase resulted primarily from an increase in compressor expenses due to the addition of more compressors and increased lease rates for our compressors. However, during 2003, we have substantially completed the process of purchasing several compressors which we previously leased. We anticipate this will reduce future compressor expenses on a per Mcf basis.

Our general and administrative expenses increased to $1.7 million in the year ended December 31, 2003 as compared to $1.5 million in the year ended December 31, 2002, an increase of $179,000 (12%). This increase primarily resulted from an increase of $600,000 in allocations of compensation and benefits from Atlas America and its affiliates due to an increase in management time spent during the year on acquisitions, potential acquisitions and our public offering. This increase was largely offset by a decrease in professional fees which, in the prior period, had been higher than normal due to costs associated with the proposed acquisition of Triton Coal Company. We were also reimbursed $156,100 by Atlas America in the year ended December 31, 2003 for one half of our unreimbursed costs associated with the proposed Triton acquisition.

Our depreciation and amortization expense increased to $1.8 million in the year ended December 31, 2003 as compared to $1.5 million in the year ended December 31, 2002, an increase of $294,900 (20%). This increase resulted from our increased asset base associated with pipeline extensions and compressor upgrades and purchases.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements, in addition to normal operating expenses, are for debt service, maintenance capital expenditures, expansion capital expenditures and quarterly distributions to our unitholders and general partner. In addition to cash generated from operations, we have the ability to meet our cash requirements, other than distributions to our unitholders and general partner, through borrowings under our credit facility. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and additional borrowings;

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- debt principal payments through additional borrowings as they become due or by the issuance of additional common units.

At December 31, 2004, we had $54.5 outstanding and $77.8 million of remaining borrowing capacity under our credit facilities.

The following table summarizes our financial condition and liquidity at the dates indicated:

	At December 3	
	2004	2003
Current ratio...	1.3x	2.9x
Working capital (in thousands)...............................	$ 7,325	$ 9,890
Ratio of long-term debt to total partners' capital............	.38x	N/A

Net cash provided by operations of $25.6 million in the year ended December 31, 2004 increased $11.9 million from $13.7 million in the year ended December 31, 2003. The increase is derived principally from an increase in net income before depreciation and amortization as a result of an increase in volumes transported and prices received for our natural gas and NGLs. Net income before depreciation and amortization was $22.8 million in the year ended December 31, 2004, an increase of $11.4 million from the year ended December 31, 2003. This increase was principally due to the acquisition of Spectrum on July 16, 2004, resulting in five and one half months of operations included in the current period. This increase was also due to the increase in the average transportation rate we received in the year ended December 31, 2004 as compared to the year ended December 31, 2003. During the year ended December 31, 2004, our accounts payable-affiliates decreased as a result of the reimbursement of advances from Atlas America in connection with expenses associated with the terminated Alaska Pipeline acquisition.

Net cash used in investing activities was $151.8 million for the year ended December 31, 2004, an increase of $142.6 million from $9.2 million in the year ended December 31, 2003. This increase was principally due to the acquisition of Spectrum on July 16, 2004. In addition, capital expenditures related to gathering system extensions and compressor upgrades to accommodate new wells increased $2.4 million.

Net cash provided by financing activities was $129.3 million for the year ended December 31, 2004, an increase of $120.6 million from $8.7 million in the year ended December 31, 2003. The primary reason for the increase was an increase in proceeds received from our public offerings of $67.5 million and increased net borrowings of $60.7 million on our revolving credit facility to fund our acquisition of Spectrum. This increase was partially offset by an increase of $6.3 million in distributions to partners in the current year period as a result of an increase in net cash flow from operations and units outstanding.

PARTNERSHIP DISTRIBUTIONS

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

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

Available cash is initially distributed 98% to our limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to unitholders exceed specified targets, as described in Item 5 of this report.

Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner's incentive distributions declared for year ended December 31, 2004 was $2.8 million.

CAPITAL EXPENDITURES

Our property and equipment was approximately 80% and 60% of our total consolidated assets at December 31, 2004 and 2003, respectively. Capital expenditures, other than the acquisition of Spectrum, were $10.0 million, $7.6 million and $5.2 million for the years ended December 31, 2004, 2003 and 2002, respectively. These capital expenditures principally consisted of costs relating to the expansion of our existing gathering systems to accommodate new wells drilled in our service area and compressor upgrades. During 2004, we connected 335 wells to our Appalachian gathering system. As of December 31, 2004, we were committed to expend approximately $8.6 million on pipeline extensions and compressor station upgrades. We anticipate that our capital expenditures will increase in 2005 as a result of an increase in the estimated number of well connections to our gathering systems.

INFLATION AND CHANGES IN PRICES

Inflation affects the operating expenses of our gathering systems.

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

ENVIRONMENTAL REGULATION

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

Environmental laws and regulations have changed substantially and rapidly over the last 25 years, and we anticipate that there will be continuing changes. One trend in environmental regulation is to increase reporting obligations and place more restrictions and limitations on activities, such as emissions of pollutants, generation and disposal of wastes and use, storage and handling of chemical substances, that may impact human health, the environment and/or endangered species. Increasingly strict environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible that the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance that we will identify and properly anticipate each such charge, or that our efforts will prevent material costs, if any, from arising.

CREDIT FACILITY

Concurrently with the completion of the Spectrum acquisition, in July 2004, we entered into a $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank that replaced our $20.0 million facility. The facility originally included a $35.0 million four year revolving line of credit and a $100.0 million five year term loan. Upon the completion of our July 2004 public offering, we repaid $40.0 million of the $100.0 million term loan we had borrowed in order to complete the acquisition of Spectrum, and in December 2004, we repaid an additional $15.0 million by borrowing $10.0 million on our revolving line of credit. In August 2004 and December 2004, the revolving credit portion of the credit facility was increased to $75.0 million and $90.0 million, respectively. Up to $5.0 million of the facility may be used for standby letters of credit. Borrowings under the facility are secured by a lien on and security interest in all of our property and that of our subsidiaries and by the guaranty of each of our subsidiaries. The credit facility bears interest at one of two rates, elected at our option:

o the base rate plus the applicable margin; or

o the adjusted LIBOR plus the applicable margin.

The base rate for any day equals the higher of the federal funds rate plus 1/2 of 1% or the Wachovia Bank prime rate. The applicable margin for the revolving line of credit is as follows:

o where our leverage ratio, that is, the ratio of its debt to our earnings before interest, taxes, depreciation and amortization, or EBITDA, is less than or equal to 2.5, the applicable margin is 1.00% for base rate loans and 2.00% for LIBOR loans;

o where our leverage ratio is greater than 2.5 but less than or equal to 3.0, the applicable margin is 1.25% for base rate loans and 2.25% for LIBOR loans;

o where our leverage ratio is greater than 3.0 but less than or equal to 3.5, the applicable margin is 1.75% for base rate loans and 2.75% for LIBOR loans; and

o where our leverage ratio is greater than 3.5, the applicable margin is 2.25% for base rate loans and 3.25% for LIBOR loans.

The applicable margin for the term loan is 0.75% higher for both base rate loans and LIBOR loans.

The credit facility requires us to maintain a ratio of funded debt to EBITDA of not more than 4.0 to 1.0, reducing to 3.5 to 1.0 on June 30, 2005 and an interest coverage ratio of not less than 3.0 to 1.0. In addition, we are required to prepay the term loan with the net proceeds of any asset sales or issuances of debt. With respect to any issuances of equity, it is required to repay the term loan from the proceeds of such issuances to the extent its ratio of funded debt to EBITDA exceeds 3.5 to 1.0. We are required to pay down $560,000 in principal on the outstanding balance of the term loan quarterly. Any prepayments of principal with proceeds from asset or equity sales that it makes will be credited pro rata against this repayment obligation.

The credit agreement contains covenants customary for loans of this size, including restrictions on incurring additional debt and making material acquisitions, and a prohibition on paying distributions to Atlas Pipeline's unitholders if an event of default occurs. The events, which constitute an event of default, are also customary for loans of this size, including payment defaults, breaches of our representations or covenants contained in the credit agreement, adverse judgments against it in excess of a specified amount, and a change of control of our general partner.

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We had $10.0 million outstanding on our revolving credit facility at a rate of 7.0% and $44.3 million outstanding on our term loan at a rate of 7.75% at December 31, 2004. In addition, we had $2.2 million outstanding under letters of credit.

Annual debt principal payments over the next five fiscal periods ending December 31 are as follows: 2005 - $2.3 million; 2006 - $2.3 million; 2007 - $2.3 million; 2008 - $10.6 million; 2009 - $36.9 million.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table summarizes our contractual obligations and commercial commitments at December 31, 2004 (in thousands):

CONTRACTUAL CASH OBLIGATIONS:	TOTAL	PAYMENTS DUE LESS THAN 1 YEAR	1 - 3 YEARS
Long-term debt..........................	$ 54,452	$ 2,303	$ 4,606
Capital lease obligations...............	11	5	6
Operating leases........................	1,146	944	202
Unconditional purchase obligations.......	-	-	-
Other long-term obligations.............	-	-	-
Total contractual cash obligations.......	$ 55,609	$ 3,252	$ 4,814

OTHER COMMERCIAL COMMITMENTS:	TOTAL	AMOUNT OF COMMITMENT E LESS THAN 1 YEAR	1 - 3 YEARS
Lines of credit.......................	$ -	$ -	$ -
Standby letters of credit.............	2,242	2,242	-
Guarantees............................	-	-	-
Standby replacement commitments........	-	-	-
Other commercial commitments..........	8,562	8,562	-
Total commercial commitments..........	$ 10,804	$ 10,804	$ -

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenues and expenses during the reporting period. Although we believe our estimates are reasonable, actual results could differ from those estimates. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Key estimates used by our management include estimates used to record revenue and expense accruals, depreciation and amortization, asset impairment and fair values of assets acquired. We summarize our significant accounting policies in Note 2 to our Consolidated Financial Statements included in this report. We discuss below the critical accounting policies that we have identified.

Revenue Recognition

We recognize revenues in the Appalachian Basin area at the time the natural gas is transported through the gathering systems. Under the terms of our natural gas gathering agreements with Atlas America and its affiliates, we receive fees for gathering natural gas from wells owned by Atlas America, by drilling investment partnerships sponsored by Atlas America or by independent third parties. The fees received for the gathering services are generally the greater of 16% of the gross sales price for gas produced from the wells, or $.35 or $.40 per mcf, depending on the ownership of the well. Substantially all gas gathering revenues are derived under this agreement. Fees for transportation services provided to independent third parties whose wells are connected to our gathering systems are at separately negotiated prices.

We recognize revenues in the Mid-Continent area at the time the natural gas is purchased, processed and the resulting residue gas and NGLs are sold. The majority of these revenues are based on POP contracts, the remainder are fixed-fee contracts. Under our POP purchasing arrangements, we purchase natural gas at the wellhead, process the natural gas by extracting NGLs and removing impurities and sell the residue gas and NGLs at market-based prices, remitting to producers a contractually-determined percentage of the sale proceeds.

We routinely make accruals for both revenues and expenses due to the timing of receiving information from third parties and reconciling our records with those of third parties. We have determined these estimates using available market data and valuation methodologies. We believe our estimates for these items are reasonable, but cannot assure you that actual amounts will not vary from estimated amounts.

Depreciation and Amortization

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

Impairment of Assets

In accordance with Statement of Financial Accounting Standards, or SFAS, 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable. We determine if our long-lived assets are impaired by comparing the carrying amount of an asset or group of assets with the estimated undiscounted future cash flows associated with such asset or group of assets. If the carrying amount is greater than the estimated undiscounted future cash flows, an impairment loss is recognized to reduce the carrying value to fair value.

Our operations are subject to numerous factors which could affect future cash flows which we discuss in Item 1, "Business-Risk Factors". We continuously monitor these factors and pursue alternative strategies to maintain or enhance cash flows associated with these assets; however, we cannot assure you that we can mitigate the effects, if any, on future cash flows related to any changes in these factors.

Goodwill

At December 31, 2004, we had $2.3 million of goodwill, all of which relates to our acquisition of pipeline assets. We test our goodwill for impairment at each year end by comparing fair values to our carrying values. The evaluation of impairment under SFAS 142, "Goodwill and Other Intangible Assets," requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Our test during the current year resulted in no impairment. We will continue to evaluate our goodwill at least annually and will reflect the impairment of goodwill, if any, in operating income in the income statement in the period in which the impairment is indicated.

Fair Value of Derivative Commodity Contracts

We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to fluctuations in natural gas and NGL prices, primarily commodity forwards, futures, swaps, options and certain basis contracts. Many of these contracts, which, in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", are not accounted for as hedges, are marked to fair value on the income statement. We utilize published settlement prices for exchange-traded contracts, and for our other contracts, use quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. The values have been adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under existing market conditions. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. . On our contracts that are designated as cash flow hedging instruments in accordance with SFAS No. 133, the effective portion of the hedged gain or loss is initially reported as a component of other comprehensive income and is subsequently reclassified into earnings when the instrument settles. The ineffective portion of the gain or loss is reported in earnings immediately.

Volume Measurement

We record amounts for natural gas gathering and transportation revenue, NGL transportation and processing revenue, natural gas sales and natural gas purchases, and the sale of production based on volumetric calculations. Variances resulting from such calculations are inherent in our business.

RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARDS

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement No. 123 (R) (revised 2004) Share-Based Payment, which is a revision of Statement of Financial Accounting Standards ("SFAS") No. 123, Accounting for Stock-Based Compensation. Statement 123 (R) supersedes Accounting Principal Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and amends Statement of Financial Accounting Standards (SFAS) No. 95, Statement of Cash Flows. Generally, the approach to accounting in Statement 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. Currently the Company accounts for these payments under the intrinsic value provisions of APB No. 25 with no expense recognition in the financial statements. Statement 123 (R) is effective for the Partnership beginning July 1, 2005. The Statement offers several alternatives for implementation. At this time, management has not made a decision as to the alternative it may select.

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

All of our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodically use derivative financial instruments.

The following analysis presents the effect on our earnings, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2004. 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, 2004, we had a $90.0 million revolving credit facility ($10.0 million outstanding) and a $45.0 million term loan ($44.3 million outstanding) to fund the expansion of our existing gathering systems and the acquisitions of other natural gas gathering systems. The weighted average interest rate for these borrowings was 7.6% at December 31, 2004.

Holding all other variables constant, if interest rates hypothetically increased or decreased by 10%, our net annual income would change by approximately $413,000.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. Based on our current contract mix, we have a long NGL position and a long gas position. Based upon our portfolio of supply contracts, a 10% change in the average price of NGLs, the average price of natural gas and the average price of crude oil sold and processed by APLMC would result in a change to our annual income of approximately $1.0 million.

Through our subsidiary, APLMC, we acquired and/or entered into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133. APLMC entered into these instruments to hedge the forecasted natural gas, natural gas liquids 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, natural gas liquids and condensate is sold. Under these swap agreements, APLMC receives a fixed price and pays a floating price based on certain indices for the relevant contract period. The options fix the price for APLMC within the puts purchased and calls sold.

Derivatives are recorded on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the effective portion of changes in fair value are recognized in stockholders' equity as Other Comprehensive Income and reclassified to earnings as such transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, changes in fair value are recognized in earnings as they occur. At December 31, 2004, we reflected a hedging liability on our Balance Sheet of $2.6 million. Of the $2.6 million liability at December 31, 2004, $1.9 million of losses will be reclassified to earnings over the next twelve month period as these contracts expire and $708,000 in later periods, if the fair values of the instruments remain constant. Actual amounts that will be reclassified will vary as a result of future changes in prices. We recognized a loss of $2,000 related to these hedging instruments in the year ended December 31, 2004. Ineffective gains or losses are recorded in income while the hedge contract is open and may increase or decrease until settlement of the contract. A loss of $257,000 resulting from ineffective hedges is included in income for the year ended December 31, 2004. These losses are included in natural gas and liquids revenues on the Partnership's Consolidated Statements of Income.

A portion of our future natural gas sales is periodically hedged through the use of swaps and collar contracts. We reflect realized gains and losses on these instruments in the contract month being hedged as an adjustment to gas revenue.

As of December 31, 2004, Atlas Pipeline had the following natural gas liquids, natural gas, and crude oil volumes hedged.

NATURAL GAS LIQUIDS FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liab
(calendar year)	(gallons)	(per gallon)	(in t
2005	12,564,000	$ 0.550	$
2006	6,804,000	0.575	
			$

NATURAL GAS FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liabi
(calendar year)	(MMBTU)(1)	(per MMBTU)	(in t
2005	970,000	$ 6.187	$
2006	450,000	5.920	
			$

CRUDE OIL FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liab
(calendar year)	(barrels)	(per barrel)	(in t
2006	18,000	$ 38.767	$

CRUDE OIL OPTIONS

Production Period	Option Type	Volumes	Average Strike Price	Fai Liab

(calendar year)		(barrels)	(per barrel)	(in t
2005	Puts purchased	75,000	$ 30.00	$
2005	Calls sold	75,000	34.30	
				$
			Total liability	$

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(1) MMBTU means Million British Thermal Units.
(2) Fair value based on APLMC internal model which forecasts forward Natural gas liquid 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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Atlas Pipeline Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, partners' capital (deficit), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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 consolidated financial position of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2004 and 2003 and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 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 Pipeline Partners, L.P.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 9, 2005 expressed an unqualified opinion.

/S/ GRANT THORNTON LLP

Cleveland, Ohio
March 9, 2005

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	DEC
	2004
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 18,214
Accounts receivable-affiliates	1,496
Accounts receivable	13,769
Prepaid expenses	1,056
Total current assets	34,535
PROPERTY, PLANT AND EQUIPMENT, NET	175,259
GOODWILL (net of accumulated amortization of $285)	2,305
OTHER ASSETS	4,686
	$ 216,785
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)	
CURRENT LIABILITIES:	
Current portion of long-term debt	$ 2,303
Accrued liabilities	3,144
Accrued hedge liability	1,959
Accrued producer liabilities	10,996
Accounts payable	2,341
Accounts payable - affiliates	-
Distribution payable	6,467
Total current liabilities	27,210
OTHER LONG-TERM LIABILITIES	722
LONG-TERM DEBT, LESS CURRENT PORTION	52,149
COMMITMENTS AND CONTINGENCIES	-
PARTNERS' CAPITAL:	
Common unitholders; 5,563,659 and 2,713,659 units outstanding	135,759
Subordinated unitholder, 1,641,026 units outstanding	2
General partner	2,261
Accumulated other comprehensive loss	(1,318)

Total partners' capital	136,704
	$ 216,785

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit data)

	YEARS ENDED DEC	
	2004	2003
REVENUES:		
Natural gas and liquids	$ 72,109	$
Transportation and compression	18,800	15,6
Interest income and other	382	
Total revenues and other income	91,291	15,7
COSTS AND EXPENSES:		
Natural gas and liquids	58,707	
Plant operating	2,032	
Transportation and compression	2,260	2,4
General and administrative	4,643	1,6
Depreciation and amortization	4,471	1,7
Gain on arbitration settlement, net	(1,457)	
Interest	2,301	2
Total costs and expenses	72,957	6,1
NET INCOME	$ 18,334	$ 9,6
NET INCOME - LIMITED PARTNERS	$ 15,256	$ 8,6
NET INCOME - GENERAL PARTNER	$ 3,078	$ 9
BASIC AND DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.60	$ 2.
WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	5,866	3,9

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	YEARS ENDE
	2004
	(in
Net income	$ 18,334
Other comprehensive (loss) income:	
Unrealized holding losses on hedging contracts	(1,320)
Reclassification adjustment for losses realized in net income	2
	(1,318)
Comprehensive income	$ 17,016

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (DEFICIT)
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002
(IN THOUSANDS, EXCEPT UNIT DATA)

	Number of Limited Partner Units		
	Common	Subordinated	Common
Balance at January 1, 2002	1,621,159	1,641,026	$ 20,128
Distributions paid to partners	-	-	(2,586)
Distribution payable	-	-	(875)
Net income	-	-	2,496
Balance at December 31, 2002	1,621,159	1,641,026	$ 19,163
Issuance of common units net of offering costs.	1,092,500	-	25,182
Capital contributions	-	-	-
Distributions paid to partners	-	-	(4,164)
Distribution payable	-	-	(1,696)
Net income	-	-	5,066
Balance at December 31, 2003	2,713,659	1,641,026	$ 43,551
Issuance of common units net of offering costs.	2,850,000	-	92,719
Capital contributions	-	-	-
Distributions paid to partners	-	-	(7,732)
Distribution payable	-	-	(4,006)
Other comprehensive loss	-	-	-
Net income	-	-	11,227
Balance at December 31, 2004	5,563,659	1,641,026	$ 135,759

	Accumulated Other Comprehensive Loss	Total Partners' Capital (Deficit)
Balance at January 1, 2002....................	$ -	$ 21,673
Distributions paid to partners................	-	(5,511)
Distribution payable..........................	-	(1,874)
Net income....................................	-	5,398
Balance at December 31, 2002..................	$ -	$ 19,686
Issuance of common units net of offering costs.	-	25,182
Capital contributions.........................	-	538
Distributions paid to partners................	-	(7,727)
Distribution payable..........................	-	(3,073)
Net income....................................	-	9,639
Balance at December 31, 2003..................	$ -	$ 44,245
Issuance of common units net of offering costs.	-	92,719
Capital contributions.........................	-	1,994
Distributions paid to partners................	-	(12,803)
Distribution payable..........................	-	(6,467)
Other comprehensive loss......................	(1,318)	(1,318)
Net income....................................	-	18,334
Balance at December 31, 2004..................	$ (1,318)	$ 136,704

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	FOR THE YEA DECEMBE	
	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income..	$ 18,334	$ 9,6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization................................	4,471	1,7
Non-cash gain on derivative value............................	(210)	
Non-cash compensation on long-term incentive plan............	700	
Loss on disposal of fixed assets.............................	8	
Amortization of deferred finance costs.......................	400	1
Change in operating assets and liabilities (net of effects of acquisition):		
Decrease in accounts receivable and prepaid expenses...	4,353	4
Increase (decrease) in accounts payable and accrued liabilities.......................................	(3,264)	4
Increase in accounts payable/receivable - affiliates..........	801	1,3

Net cash provided by operating activities..................	25,593	13,7
CASH FLOWS FROM INVESTING ACTIVITIES:		
Business acquisition, net of cash acquired.......................	(141,626)	
Capital expenditures...	(10,043)	(7,6
Increase in other assets...	(316)	(1,5
Proceeds from sale of fixed assets...............................	188	
Net cash used in investing activities......................	(151,797)	(9,1
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on credit facilities..................................	110,000	2,0
Repayments on credit facilities..................................	(55,750)	(8,5
Issuance of common units net of offering costs...................	92,719	25,1
Capital contributions..	1,994	5
Distributions paid to partners...................................	(15,876)	(9,6
Increase in other assets...	(3,747)	(9
Net cash provided by (used in) financing activities.........	129,340	8,6
Increase (decrease) in cash and cash equivalents..................	3,136	13,2
Cash and cash equivalents, beginning of year.....................	15,078	1,8
Cash and cash equivalents, end of year...........................	$ 18,214	$ 15,0

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - NATURE OF OPERATIONS

THE PARTNERSHIP

Atlas Pipeline Partners, L.P. (the "Partnership") is a Delaware limited partnership formed in May 1999 to acquire, own and operate natural gas gathering systems theretofore owned by Atlas America, Inc. ("Atlas" or "Atlas America") and its affiliates, Viking Resources Corporation ("VRC") and Resource Energy, Inc. ("REI") (collectively referred to as the "Predecessor"). Atlas America is an 80% owned subsidiary of Resource America, Inc. ("RAI" or "Parent"). In May 2004, Atlas completed its initial public offering of 2,645,000 shares of its common stock, which trades under the symbol ATLS on the NASDAQ system. RAI is a publicly traded company (NASDAQ:REXI) operating in the structured finance, equipment leasing, real estate and energy sectors.

PARTNERSHIP STRUCTURE AND MANAGEMENT

The Partnership's operations are conducted through subsidiary entities whose equity interests are owned by the Partnership's operating subsidiary, Atlas Pipeline Operating Partnership, L.P., (the "Operating Partnership"). Atlas Pipeline Partners GP, LLC (a wholly-owned subsidiary of Atlas (the "General Partner")), owns, through its general partner interests in the Partnership and the Operating Partnership, a 2% general partner interest in the consolidated pipeline operations. The remaining 98% consists of limited partner interests of which 77% consists of common units ("Common Units") and 23% consists of subordinated units ("Subordinated Units"). The Subordinated Units are subordinated to the rights of the holders of Common Units. On January 1, 2005, the subordination period ended and the subordinated units converted into Common Units on a one-for-one basis. Through its general partner interest, the General Partner effectively manages and controls both the Partnership and the Operating Partnership.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A summary of the significant accounting policies consistently applied in the preparation of the accompanying consolidated financial statements follows.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership's wholly-owned subsidiaries. The General Partner's interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership, as opposed to a minority interest. All material intercompany transactions have been eliminated.

ACCOUNTING ESTIMATES

Certain amounts included in or affecting the Partnership's consolidated financial statements and related disclosures must be estimated, requiring the Partnership to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared.

The preparation of its consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires the Partnership to make estimates and assumptions that affect:

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - (CONTINUED)

ACCOUNTING ESTIMATES - (CONTINUED)

- the amount the Partnership reports for assets and liabilities;
- the Partnership's disclosure of contingent assets and liabilities at the date of the financial statements; and
- the amounts the Partnership reports for revenues and expenses during the reporting period.

Therefore, the reported amounts of the Partnership's assets and liabilities, revenues and expenses and associated disclosures with respect to contingent assets and obligations are necessarily affected by these estimates. The Partnership evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods the Partnership considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Partnership's estimates. Any effects on the Partnership's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

RECLASSIFICATIONS

Certain reclassifications have been made to the 2003 and fiscal 2002 consolidated financial statements to conform to the 2004 presentation.

PROPERTY AND EQUIPMENT

Depreciation is provided for in amounts sufficient to relate the cost of depreciable assets to operations over the estimated useful lives of the assets. Gas gathering, transmission and processing facilities are depreciated over 15 to 40 years using the straight-line method. Other equipment is depreciated over 5 to 10 years using the straight-line method.

IMPAIRMENT OF LONG-LIVED ASSETS

The Partnership reviews its long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

DISTRIBUTIONS

The Partnership is required to distribute, within 45 days of the end of each quarter, all of its available cash (as defined in the partnership agreement) for that quarter. For each quarter during the subordination period (through December 31, 2004), to the extent there is sufficient cash available, the Common Unit holders have the right to receive a minimum quarterly distribution ("MQD") of $.42 per unit prior to any distribution to the subordinated units. If distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - (CONTINUED)

ENVIRONMENTAL MATTERS

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

The Partnership accounts for environmental contingencies in accordance with SFAS 5, "Accounting for Contingencies." Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. The Partnership maintains insurance which may cover in whole or in part certain environmental expenditures. For the three years ended December 31, 2004, the Partnership had no environmental matters requiring specific disclosure or requiring recording of a liability.

SEGMENT INFORMATION

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

REVENUE RECOGNITION

Revenues in the Appalachian Basin area are recognized at the time the natural gas is transported through the gathering systems. Under the terms of its natural gas gathering agreements with Atlas and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas, by drilling investment partnerships sponsored by Atlas or by independent third parties. The fees received for the gathering services are generally the greater of 16% of the gross sales price for gas produced from the wells, or $.35 or $.40 per thousand cubic feet ("mcf"), depending on the ownership of the well. Substantially all gas gathering revenues are derived under this agreement. Fees for transportation services provided to independent third parties whose wells are connected to the Partnership's gathering systems are at separately negotiated prices.

Revenues in the Mid-Continent area are recognized at the time the natural gas is processed and the resulting residue gas and natural gas liquids ("NGLs") are sold. The majority of these revenues are based on percentage of proceeds, or POP contracts; the remainder are fixed-fee contracts. Under its POP purchasing arrangements, the Partnership purchases natural gas at the wellhead, processes the natural gas by extracting NGLs and removing impurities and sells the residue gas and NGLs at market-based prices, remitting to producers a contractually-determined percentage of the sale proceeds.

FAIR VALUE OF FINANCIAL INSTRUMENTS

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair values because of the short maturity of these instruments. The carrying value of long-term debt approximates fair market value since interest rates approximate current market rates.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - (CONTINUED)

FAIR VALUE OF FINANCIAL INSTRUMENTS-(CONTINUED)

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

	DECEMBER 31, 2004	
	BOOK VALUE	FAIR VALUE
Assets		
Derivative instruments..............	$ 54	$ 54
	$ 54	$ 54

Liabilities		
Derivative instruments..............	$ (2,681)	$ (2,681)
	$ (2,681)	$ (2,681)
	$ (2,627)	$ (2,627)

DERIVATIVE INSTRUMENTS

The Partnership 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.

CASH FLOW STATEMENTS

For purposes of the statements of cash flows, all highly liquid debt instruments purchased with a maturity of three months or less are considered to be cash equivalents. Supplemental disclosure of cash flow information (in thousands):

	FOR THE YEAR DECEMBER	
	2004	2003
Cash paid during the period for:		
Interest..	$ 2,065	$ 1
Non-cash activities include the following:		
Fair value of assets acquired...............................	$ 160,462	$
Liabilities assumed...	(18,836)	
Net cash paid for Spectrum.................................	$ 141,626	$

The Partnership had distributions payable of $6,467, $3,073 and $1,874 at December 31, 2004, 2003, and 2002 respectively.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - (CONTINUED)

CONCENTRATION OF CREDIT RISK

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist principally of periodic temporary investments of cash. The Partnership places its temporary cash investments in high quality short-term money market instruments and deposits with high quality financial institutions. At December 31, 2004, the Partnership and its subsidiaries had $21.9 million in deposits at one bank, of which $21.6 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments. Also see Note 16 with regards to major customers.

GOODWILL

At December 31, 2004, the Partnership had $2.3 million of goodwill, all of which relates to its acquisition of pipeline assets. The Partnership tests its goodwill for impairment at each year end by comparing fair values to its carrying values. The evaluation of impairment under SFAS 142, "Goodwill and Other Intangible Assets," requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to the Partnership's assumptions and, if required, recognizing an impairment loss. The Partnership's test during the current year resulted in no impairment. The Partnership will continue to evaluate its goodwill at least annually and will reflect the impairment of goodwill, if any, in operating income in the income statement in the period in which the impairment is indicated.

COMPREHENSIVE INCOME (LOSS)

Comprehensive (loss) income includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" and for the Partnership include changes in the fair value of derivative contracts accounted for as hedges. The components of accumulated other comprehensive (loss) income are as follows:

	DECE
	2004
Accumulated other comprehensive income (loss), beginning of period	$ -
Other comprehensive loss:	
Unrealized loss on hedging contracts............................	(1,320)
Less: reclassification adjustment for losses realized in net income	2
Accumulated other comprehensive loss, end of period..............	$ (1,318)

FEDERAL INCOME TAXES

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

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - (CONTINUED)

STOCK BASED COMPENSATION

The Partnership issues phantom units to its directors and employees of Atlas America and its affiliates under its Long-Term Incentive Plan ("the Plan") (see Notes 8 and 15). The Partnership accounts for the issuances under this Plan under the Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and its related interpretations.

RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARD

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement No. 123 (R) (revised 2004) Share-Based Payment, which is a revision of Statement of Financial Accounting Standards ("SFAS") No. 123, Accounting for Stock-Based Compensation. Statement 123 (R) supersedes Accounting Principal Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and amends Statement of Financial Accounting Standards (SFAS) No. 95, Statement of Cash Flows. Generally, the approach to accounting in Statement 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. Currently the Company accounts for these payments under the intrinsic value provisions of APB No. 25 with no expense recognition in the financial statements. Statement 123 (R) is effective for the Partnership beginning July 1, 2005. The Statement offers several alternatives for implementation. At this time, management has not made a decision as to the alternative it may select.

NOTE 3 - NET INCOME PER UNIT

Net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the period. Basic net income per limited partner unit is computed by dividing net income, after deducting the general partner's 2% and incentive distributions, by the weighted average number of outstanding common units and subordinated units. Diluted net income per limited partner unit is computed by dividing net income attributable to limited partners by the sum of the weighted average number of common and subordinated units outstanding and the weighted average number of phantom units during the period. Phantom units consist of common units issuable under the terms of the Partnership's Long-Term Incentive Plan.

Phantom units issued in 2004 totaling 58,752 units were not included in the computation of diluted net income per limited partner unit for the year ended December 31, 2004 as their effect would have been anti-dilutive.

NOTE 4- PROPERTY, PLANT AND EQUIPMENT

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

NOTE 4 - PROPERTY, PLANT AND EQUIPMENT - (CONTINUED)

	DEC
	2004
Pipelines, processing and compression facilities	$ 168,846
Rights of way	14,128
Buildings and improvements	3,334
Furniture and equipment	508
Other	283
	187,099
Less - accumulated depreciation	(11,840)
	$ 175,259

NOTE 5 - OTHER ASSETS

The following is a summary of the Partnership's other assets (in thousands):

	DEC
	2004
Deferred finance costs, net of accumulated amortization of $506 and $106	$ 3,316
Security deposits	1,356
Alaska Pipeline Company acquisition costs (see Note 14)	-
Other	14
	$ 4,686

Deferred finance costs are recorded at cost and amortized over the five-year term of the associated debt, which expires on July 15, 2009.

NOTE 6 -SPECTRUM ACQUISITION

On July 16, 2004, the Partnership acquired Spectrum Field Services, Inc. ("Spectrum or Mid-Continent"), for approximately $142.4 million, including transaction costs and the payment of taxes due as a result of the transaction. Spectrum's principal assets include 1,900 miles of natural gas pipelines and a natural gas processing facility in Velma, Oklahoma. Spectrum has changed its name to Atlas Pipeline Mid-Continent, LLC ("APLMC"). This acquisition significantly increased the Partnership's size and diversifies the natural gas supply basins in which it operates and the natural gas midstream services it provides to its customers.

In connection with the acquisition of Spectrum, the Partnership entered into commitment agreements with Resource America and Atlas America for the purchase of up to $25.0 million of preferred units in the Operating Partnership. In consideration for their commitments, upon the closing of the Spectrum acquisition and the purchase by each of $10.0 million of preferred units, the Partnership paid Resource America and Atlas America commitment fees of $750,000 and $500,000, respectively.

In April and July 2004, the Partnership 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 $67.5 million, respectively. The General Partner simultaneously contributed $535,000 and $1.5 million to the Partnership in order to maintain its 2% general partner interest in the Partnership.

NOTE 6 - SPECTRUM ACQUISITION - (CONTINUED)

The Partnership financed the Spectrum acquisition, including approximately $4.3 million of transaction costs, as follows:

- borrowing $100.0 million under the term loan portion of its $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association (Note 11);

- using the $20.0 million of proceeds received from the sale to Resource America and Atlas America of preferred units in the Operating Partnership; and

- using $22.4 million of net proceeds from the Partnership's April 2004 common unit offering.

On July 20, 2004, the Partnership used a portion of the July 2004 public offering to repay $40.0 million of the borrowings under its $135.0 million credit facility and to repurchase the preferred units from Resource America and Atlas America for $20.4 million.

On March 9, 2004, the Oklahoma Tax Commission ("OTC") filed a petition against Spectrum alleging that Spectrum underpaid gross production taxes beginning in June 2000. The OTC is seeking a settlement of $5.0 million plus interest and penalties. The Partnership plans on defending itself vigorously. In addition, under the terms of the Spectrum purchase agreement, $14.0 million has been placed in escrow to cover the costs of any adverse settlement resulting from the petition and other indemnification obligations of the purchase agreement.

The acquisition was accounted for using the purchase method of accounting under SFAS No. 141 "Business Combinations." The following table presents the allocation of the acquisition cost, 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	140,254
Other long-term assets	1,054
Total assets acquired	161,265
Accounts payable and accrued liabilities	(17,084)
Hedging liabilities	(1,519)
Long-term debt	(233)
Total liabilities assumed	(18,836)

Net assets acquired.....................................	$ 142,429

The Partnership is in the process of evaluating certain estimates made in the purchase price and related allocations; thus, the purchase price and allocation are both subject to adjustment.

The results of operations of Spectrum are included in the Partnership's consolidated statements of income from July 16, 2004, the date of the acquisition.

The following summarized pro forma consolidated income statement information for the years ended December 31, 2004 and 2003, assumes that the acquisition discussed above occurred as of January 1, 2003.

NOTE 6 -SPECTRUM ACQUISITION - (CONTINUED)

The Partnership 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 the Partnership had completed this acquisition as of the periods shown below or the results that will be attained in the future. The amounts presented below are in thousands, except per unit amounts:

	YEAR ENDED DECEMBER 31, 2004	
		(UNAUDITED)
	AS REPORTED	PRO FORMA ADJUSTMENTS
Revenues..	$ 91,291	$ 67,643
Net income..	$ 18,334	$ 8,925
Basic net income per limited partner unit..................	$ 2.60	$ 0.74
Weighted average number of limited partner units used for basic net income per unit calculation.....................	5,866	1,339

	YEAR ENDED DECEMBER 31, 2003	
		(UNAUDITED)
	AS REPORTED	PRO FORMA ADJUSTMENTS
Revenues..	$ 15,749	$ 100,958
Net income..	$ 9,639	$ (1,423)
Basic net income per limited partner unit..................	$ 2.17	$ (1.12)
Weighted average number of limited partner units used for basic net income per unit calculation.....................	3,981	2,926

During the year ended December 31, 2003 Spectrum added a new purchaser to its systems and as such, revenues in that year and are not indicative of results that will be expected in the future. In addition Spectrum incurred one-time expenses for a lawsuit settlement and a loss on disposal of an asset group during that year.

NOTE 7 - DERIVATIVE INSTRUMENTS

The Partnership, through its subsidiary, APLMC, acquired and/or entered into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133. APLMC entered into these instruments to hedge the forecasted natural gas, natural gas liquids 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, natural gas liquids and condensate is sold. Under these swap agreements, APLMC receives a fixed price and pays a floating price based on certain indices for the relevant contract period. The options fix the price for APLMC within the puts purchased and calls sold.

NOTE 7 -DERIVATIVE INSTRUMENTS - (CONTINUED)

The Partnership formally documents all relationships between hedging instruments and the items being hedged, including the Partnership's risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. The Partnership 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. 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, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in fair value for the derivative will be recognized immediately into earnings.

Derivatives are recorded on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the effective portion of changes in fair value are recognized in stockholders' equity as Other Comprehensive Income and reclassified to earnings as such transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, changes in fair value are recognized in earnings as they occur. At December 31, 2004, APLMC reflected a net hedging liability on its Balance Sheet of $2.6 million. Of the $2.6 million net liability at December 31, 2004, $1.9 million ($40,000 is included in accounts receivable, less $2.0 million shown as accrued hedge liability on the consolidated balance sheet) of losses will be reclassified to earnings over the next twelve month period as these contracts expire and $708,000 ($14,000 is included in other assets, less $722,000 shown as other long-term liabilities on the consolidated balance sheet) will be reclassified in later periods, if the fair values of the instruments remain constant. Actual amounts that will be reclassified will vary as a result of future changes in prices. The Company recognized a loss of $2,000 related to these hedging instruments in the year ended December 31, 2004. Ineffective gains or losses are recorded in income while the hedge contract is open and may increase or decrease until settlement of the contract. A loss of $257,000 resulting from ineffective hedges is included in income for the year ended December 31, 2004. These losses are included in natural gas and liquids revenues on the Partnership's Consolidated Statements of Income.

A portion of the Company's future natural gas sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on these instruments are reflected in the contract month being hedged as an adjustment to gas revenue.

As of December 31, 2004, The Partnership had the following natural gas liquids, natural gas, and crude oil volumes hedged.

NATURAL GAS LIQUIDS FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liab
(calendar year)	(gallons)	(per gallon)	(in t
2005	12,564,000	$ 0.550	$
2006	6,804,000	0.575	
			$

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (CONTINUED)

NOTE 7 -DERIVATIVE INSTRUMENTS - (CONTINUED)

NATURAL GAS FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liab
(calendar year)	(MMBTU)(1)	(per MMBTU)	(in t
2005	970,000	$ 6.187	$
2006	450,000	5.920	
			$

CRUDE OIL FIXED - PRICE SWAPS

Production Period	Volumes	Average Fixed Price	Fai Liab
(calendar year)	(barrels)	(per barrel)	(in t
2006	18,000	$ 38.767	$

CRUDE OIL OPTIONS

Production Period	Option Type	Volumes	Average Fixed Price	Fai Liab
(calendar year)		(barrels)	(per barrel)	(in t
2005	Puts purchased	75,000	$ 30.00	$
2005	Calls sold	75,000	34.30	
				$
			Total liability	$

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(1) MMBTU means Million British Thermal Units.
(2) Fair value based on APLMC internal model which forecasts forward natural gas liquid 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.

NOTE 8 - SPECIAL MEETING OF UNITHOLDERS

On February 11, 2004, at a special meeting of unitholders, the following were approved:

- The issuance of up to 2.0 million common units in connection with the Partnership's proposed acquisition of Alaska Pipeline Company, of which 750,000 common units were issued in April 2004 (see Note 6).

- The Atlas Pipeline Partners, L.P. Long-Term Incentive Plan in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner's affiliates, consultants and joint venture partners who perform services for the Partnership are eligible to participate. The Plan is administered by a committee appointed by the General Partner's managing board (the "Committee"), which sets the terms of awards under the Plan. The Committee may make awards of either phantom units or options for an aggregate of 435,000 common units, provided that the maximum number of phantom units that may be awarded in total to non-employee managing board members is 10,000. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant the right, known as a DER, to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. An option entitles the grantee to purchase the Partnership's common units at an exercise price determined by the Committee, which may be less than, equal to or more than the fair market value of the Partnership's common units on the date of the grant. The Committee also has

NOTE 8 - SPECIAL MEETING OF UNITHOLDERS - (CONTINUED)

discretion to determine how the exercise price may be paid. Except for phantom units awarded to non-employee managing board members of the General Partner, the managing board will determine the vesting period for phantom units and the exercise period for options. Phantom units awarded to non-employee managing board members will vest over a 4-year period at the rate of 25% per year. Both types of awards will automatically vest upon a change of control, as defined in the Plan (see Note 15).

After the special meeting of unitholders was adjourned and was reconvened on March 9, 2004, the unitholders approved amendments to the Partnership Agreement that removed the limitations on the Partnership's ability to issue common units and incur debt.

NOTE 9 - RELATED PARTY TRANSACTIONS

The Partnership is affiliated with RAI and its subsidiaries, including Atlas, VRC and REI ("Affiliates"). The Partnership is dependent upon the resources and services provided by RAI and these Affiliates. Accounts receivable/payable-affiliates represents the net balance due from/to these Affiliates for natural gas transported through the gathering systems, net of reimbursements for Partnership costs and expenses paid by these Affiliates. Substantially all Partnership revenue in Appalachia is from these Affiliates.

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of RAI and/or its Affiliates. The General Partner does not receive a management fee or other compensation in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses Atlas and/or its Affiliates for all direct and indirect costs of services provided, including the cost of employees, officer and managing board member compensation and benefits properly allocable to the Partnership and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership.

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. For the years ended December 31, 2004, 2003 and 2002, such reimbursements were approximately $15.9 million, $11.7 million and $8.8 million, respectively, including certain costs that have been capitalized by the Partnership.

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

Atlas had agreed to provide the Partnership with financing for the cost of constructing new gathering system expansions through February 2, 2005, on a stand-by basis. The commitment was for a maximum of $1.5 million in any contract year. This commitment expired without being used.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (CONTINUED)

NOTE 9 - RELATED PARTY TRANSACTIONS - (CONTINUED)

In connection with the proposed acquisition of Alaska Pipeline Company, L.L.C. ("Alaska Pipeline") (see Note 14), the Partnership paid RAI a fee of $70,750 in the year ended December 31, 2004.

NOTE 10 - DISTRIBUTION DECLARED

The Partnership makes quarterly cash distributions of its available cash, generally defined as cash on hand at the end of the quarter less cash reserves deemed appropriate to provide for future operating costs, potential acquisitions and future distributions.

On December 17, 2004, the Partnership declared a cash distribution of $0.72 per unit on its outstanding common units and subordinated units. The distribution represents the available cash flow less cash reserves for the three months ended December 31, 2004. The $6.5 million distribution, which includes a distribution of $1.3 million to the general partner, will be paid on February 11, 2005 to unitholders of record on December 31, 2004.

Available cash is initially distributed 98% to limited partners and 2% to the general partner. These distribution percentages are modified to provide for incentive distributions to be paid to the general partner in the event that quarterly distributions to unitholders exceed certain specified targets. Incentive distributions are generally defined as all cash distributions paid to the general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner's incentive distributions for the distributions declared for the year ended December 31, 2004, 2003 and 2002 were $2.8 million, $809,000 and $272,000, respectively.

NOTE 11 -CREDIT FACILITIES

Total debt consists of the following at the dates indicated:

	At December 31, 2004	At December 31, 2003
	(in thousands)	
Revolving credit facility..................	$ 10,000	$ -
Term loan..................................	44,250	-
Other debt.................................	202	-
	54,452	-
Less current maturities....................	2,303	-
	$ 52,149	$ -

Concurrently with the completion of the Spectrum acquisition, in July 2004, the Partnership entered into a $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank that replaced its $20.0 million facility. The facility originally included a $35.0 million four year revolving line of credit and a $100.0 million five year term loan.

NOTE 11 -CREDIT FACILITIES - (CONTINUED)

Upon the completion of its July 2004 public offering, the Partnership repaid $40.0 million of the $100.0 million term loan it had borrowed in order to complete the acquisition of Spectrum, and in December 2004, the Partnership repaid an additional $15.0 million by borrowing $10.0 million on its revolving line of credit. In August 2004 and December 2004, the revolving credit portion of the facility was increased to $75.0 million and $90.0 million, respectively. Up to $5.0 million of the facility may be used for standby letters of credit. Borrowings under the 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 bears interest at one of two rates, elected at the Partnership's option:

- o the base rate plus the applicable margin; or

- o the adjusted LIBOR plus the applicable margin.

The base rate for any day equals the higher of the federal funds rate plus 1/2 of 1% or the Wachovia Bank prime rate. The applicable margin for the revolving line of credit is as follows:

- where the Partnership's leverage ratio, that is, the ratio of its debt to earnings before interest, taxes, depreciation and amortization, or EBITDA, is less than or equal to 2.5, the applicable margin is 1.00% for base rate loans and 2.00% for LIBOR loans;

- where its leverage ratio is greater than 2.5 but less than or equal to 3.0, the applicable margin is 1.25% for base rate loans and 2.25% for LIBOR loans;

- where its leverage ratio is greater than 3.0 but less than or equal to 3.5, the applicable margin is 1.75% for base rate loans and 2.75% for LIBOR loans; and

- where its leverage ratio is greater than 3.5, the applicable margin is 2.25% for base rate loans and 3.25% for LIBOR loans.

The applicable margin for the term loan is 0.75% higher for both base rate loans and LIBOR loans.

The credit facility requires the Partnership to maintain a ratio of funded debt to EBITDA of not more than 4.0 to 1.0, reducing to 3.5 to 1.0 on June 30, 2005 and an interest coverage ratio of not less than 3.0 to 1.0. In addition, the Partnership is required to prepay the term loan with the net proceeds of any asset sales or issuances of debt. With respect to any issuances of equity, it is required to repay the term loan from the proceeds of such issuances to the extent its ratio of funded debt to EBITDA exceeds 3.5 to 1.0. The Partnership is required to pay down $560,000 in principal on the outstanding balance of the term loan quarterly. Any prepayments of principal with proceeds from asset or equity sales that it makes will be credited pro rata against this repayment obligation.

The credit agreement contains covenants customary for loans of this size, including restrictions on incurring additional debt and making material acquisitions, and a prohibition on paying distributions to the Partnership's unitholders if an event of default occurs. The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of the Partnership's representations or covenants contained in the credit agreement, adverse judgments against it in excess of a specified amount, and a change of control of its general partner.

NOTE 11 -CREDIT FACILITY - (CONTINUED)

The Partnership had $10.0 million outstanding on its revolving credit facility at a rate of 7.0% and $44.3 million outstanding on it term loan at a rate of 7.75% at December 31, 2004. In addition, the Partnership had $2.2 million outstanding under letters of credit.

Annual debt principal payments over the next five fiscal periods ending December 31 are as follows: 2005 - $2.3 million; 2006 - $2.3 million; 2007 - $2.3 million; 2008 - $10.6 million; 2009 - $36.9 million.

NOTE 12 - LEASES AND COMMITMENTS

The Partnership leases equipment and office space with varying expiration dates through 2007. Rent expense for the years ended December 31, 2004, 2003 and 2002 was $830,000, $1,039,000 and $840,000, respectively. Minimum future lease payments for these leases in 2005, 2006 and 2007 are $944,000, $161,000 and $41,000, respectively.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

The Partnership is 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 Partnership's financial condition or results of operations.

NOTE 14 - SETTLEMENT OF TERMINATED ALASKA PIPELINE ARBITRATION

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

NOTE 15 - LONG-TERM INCENTIVE PLAN

The Partnership has a Long-Term Incentive Plan as discussed in Note 8. During the year ended December 31, 2004, 59,598 phantom units were granted. Grants for 846 units were forfeited during the three months ended June 30, 2004, leaving 58,752 phantom units outstanding as of December 31, 2004. The Partnership recognized $821,000 in compensation expense related to these grants and their associated distributions in the year ended December 31, 2004. The fair market value associated with these grants at December 31, 2004 was $2.5 million which will be amortized into expense over the vesting period of the units.

NOTE 15 - LONG-TERM INCENTIVE PLAN - (CONTINUED)

A summary of the fair market value of equity-based incentive compensation awards of phantom units for the years ended December 31, 2004, is listed below (in thousands, except per unit data).

	2004
Incentive compensation awards	$ 2,213
Forfeitures	(30)
Total outstanding awards	$ 2,183

Weighted average fair-value of phantom units granted..	$ 37.16

The following table summarizes certain information about the Partnership's Long-Term Incentive Plan as of December 31, 2004.

	(a)	(b)	
Plan category	Number of securities to be issued upon exercise of phantom units	Weighted-average exercise price of outstanding phantom units	Numbe avail under exclu
Equity compensation plans approved by security holders	58,752	$ 0	

NOTE 16 - OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS

The Partnership's operations include two reportable operating segments. In addition to the reportable operating segments, certain other activities are reported in the "Other" category. These operating segments reflect the way the Partnership manages its operations and makes business decisions.

Operating segment data (in thousands):

YEAR ENDED DECEMBER 31, 2004:

	Revenues from external customers	Interest income	Interest expense	Depreciation, depletion and amortization	S prof
Mid-Continent	$ 72,109	$ 26	$ 11	$ 2,408	$
Appalachia	18,800	224	-	2,063	
Other(a)	-	19	2,290	-	
Total	$ 90,909	$ 269	$ 2,301	$ 4,471	$

NOTE 16 - OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS - (CONTINUED)

YEAR ENDED DECEMBER 31, 2003:

	Revenues from external customers	Interest income	Interest expense	Depreciation, depletion and amortization	S prof
Mid-Continent	$ -	$ -	$ -	$ -	$
Appalachia	15,651	20	-	1,770	
Other(a)	-	56	258	-	
Total	$ 15,651	$ 76	$ 258	$ 1,770	$

(a) Includes revenues and expenses which do not meet the quantitative threshold for reporting segment information and general corporate expenses not allocable to any particular segment.

Segment profit (loss) represents total revenues less costs and expenses attributable thereto, including interest and depreciation and amortization.

The Partnership sells natural gas and NGLs under contract to various purchasers in the normal course of business. For the year ended December 31, 2004, Mid-Continent had two purchasers that accounted for approximately 34% and 25% of the Partnership's revenues. Additionally, two purchasers accounted for 39% and 31% of Mid-Continent's trade receivable at December 31, 2004. Substantially all Appalachian revenues are derived from a master gas gathering agreement with Atlas America.

NOTE 17 - QUARTERLY FINANCIAL DATA (UNAUDITED)

	March 31	June 30	Sept
	(in thousands, except per		
YEAR ENDED DECEMBER 31, 2004:			
Revenues...	$ 4,246	$ 4,549	$
Costs and expenses...................................	1,769	1,776	
Net income...	2,477	2,773	
Net income - limited partners........................	2,122	2,359	
Net income - general partner.........................	355	414	
Basic and diluted net income per limited partner unit..	0.49	0.47	
Weighted average limited partner units outstanding.....	4,355	5,039	

	March 31	June 30	Sept
	(in thousands, except per		
YEAR ENDED DECEMBER 31, 2003			
Revenues...	$ 3,330	$ 4,348	$
Costs and expenses...................................	1,418	1,662	
Net income...	1,912	2,686	
Net income - limited partners........................	1,780	2,479	
Net income - general partner.........................	132	207	
Basic and diluted net income per limited partner unit..	0.55	0.63	
Weighted average limited partner units outstanding.....	3,262	3,934	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (CONTINUED)

NOTE 18 - SUBSEQUENT EVENTS

On March 8, 2005 the Partnership entered into an agreement to acquire all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd., a Texas limited partnership for $190 million in cash and subject to certain post-closing adjustments, including gas imbalances, certain prepaid costs and expenses and capital expenditures, and any defects. The transaction is expected to be completed in the second quarter of 2005 and is conditioned on the receipt of various approvals, including Hart-Scott-Rodino Act approval and other customary closing conditions. ETC Oklahoma Pipeline's principal assets include more than 315 miles of natural gas pipeline, a natural gas processing facility and a gas treatment plant in western Oklahoma. The acquisition expands the Partnership activities in the mid-continent area and provides the potential for further growth to APLMC's operations based in Tulsa, Oklahoma.

To finance the acquisition, the Partnership has received a commitment from Wachovia Bank, National Association and Fleet National Bank, a Bank of America company, to fully underwrite a new $270 million loan facility. The facility will be comprised of a $225 million 5-year revolving loan and a $45 million 5-year term loan. The loan proceeds will be used to refinance the existing $54 million outstanding on the partnership's current $135 million facility and to finance the acquisition of ETC Oklahoma Pipeline.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of management, including our General Partner's principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods 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.

In conducting our evaluation of the effectiveness of our internal control over financial reporting, we have excluded due to its size and complexity the acquisition of Spectrum Field Services, Inc. which changed its name to Atlas Pipeline Mid-Continent, ("APLMC") which was completed in July 2004. This acquisition created a second geographic location with a business line distinct from that of our Appalachian operations in which financial reporting will continue to occur with their own control environment, control activities and proprietary information technology systems. Collectively, this acquisition constituted 74% of total assets as of December 31, 2004, 76% of total revenues and 43% of net earnings for the year then ended (See Note 6 to the consolidated financial statements which contains further discussion of this acquisition and its impact on our consolidated financial statements). We plan to fully integrate our two financial reporting locations (APLMC and our existing Appalachian operations) into a common financial reporting framework in 2005.

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Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Atlas Pipeline Partners, L.P.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Atlas Pipeline Partners, L.P. ("the Partnership") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the partnership's internal control over financial reporting based on our audit.

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

In conducting management's evaluation of the effectiveness of its internal control over financial reporting, management has excluded, due to its size and complexity, the Partnership's subsidiary, Atlas Pipeline Mid-Continent, LLC, (formerly Spectrum Field Services, Inc.) which was recently acquired in July 2004. This acquisition created a second geographic location with a business line distinct from that of the Partnership's Appalachian operations. Financial reporting for this new acquisition is performed within a separate control environment containing separate control activities and proprietary information technology systems. Collectively, this acquisition constituted 74% of total consolidated assets as of December 31, 2004 and 76% and 43%, respectively, of consolidated revenues and net earnings for the year then ended. We believe that management had sufficient cause to exclude this acquisition in its evaluation of the effectiveness of its internal control over financial reporting based on the size and complexity, and timing of the acquisition.

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 Partnership maintained effective internal control over financial reporting as of December 31, 2004, 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 Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, 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 Partnership and its subsidiaries as of December 31, 2004 and 2003, and related consolidated statements of income, comprehensive income, partners' capital (deficit) and cash flows for each of the three years ended December 31, 2004, and our report dated March 9, 2005 expressed an unqualified opinion on those financial statements.

/S/ GRANT THORNTON LLP

Cleveland, Ohio
March 9, 2005

ITEM 9B. OTHER INFORMATION

On December 3, 2004, our revolving credit and term loan facility administered by Wachovia Bank, N.A. was amended to increase the maximum availability under the revolver portion of the facility to $90.0 million. At the same time, we repaid $15.0 million under the term loan portion of the facility. See Note 11 to our Consolidated Financial Statements.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE GENERAL PARTNER

Our general partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us. Our general partner will be liable, as general partner, for all of our debts to the extent not paid, except to the extent that indebtedness or other obligations incurred by us are specifically with recourse only to our assets. Whenever possible, our general partner intends to make any of our indebtedness or other obligations with recourse only to our assets.

Three members of the managing board of our general partner who are neither officers nor employees of our general partner nor directors, managing board members, officers or employees of any affiliate of our general partner (and have not been for the past five years) serve on the conflicts committee. Messrs. Michael Bradley, Curtis Clifford and Murray Levin currently serve as the conflicts committee of the managing board. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest in order to determine if the resolution of the conflict proposed by our general partner is fair and reasonable to us. Any matters approved by the conflicts committee are conclusively judged to be fair and reasonable to us, approved by all our partners and not a breach by our general partner or its managing board of any duties they may owe us or the unitholders. In addition, the members of the conflicts committee also constitute an audit committee which reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls. Mr. Bradley has been designated as the audit committee financial expert by the board of managers of the general partner, who determined that he is independent within the meaning of Item 7(d)(3)(iv) of Schedule 14A of the Securities Exchange Act.

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

MANAGING BOARD MEMBERS AND EXECUTIVE OFFICERS OF OUR GENERAL PARTNER

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

NAME	AGE	POSITION WITH GENERAL PARTNER

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Edward E. Cohen	66	Chairman of the Managing Board and Chief Executive Officer
Jonathan Z. Cohen	34	Vice Chairman of the Managing Board
Michael L. Staines	55	President, Chief Operating Officer and Managing Board Member
Freddie M. Kotek	49	Chief Financial Officer
Tony C. Banks	50	Managing Board Member
Michael J. Bradley	60	Managing Board Member
Curtis D. Clifford	62	Managing Board Member
Murray S. Levin	62	Managing Board Member

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Edward E. Cohen has been Chairman of the Board of Directors of Resource America since 1990, and a director since 1988. Mr. Cohen served as Chief Executive Officer and a director of Resource America from 1988 to May 2004 and President of Resource America from 2000 to 2003. He has been Chairman of the Board of Directors and Chief Executive Officer of Atlas America from its formation in 2000. He is Chairman of the Board of Directors of Brandywine Construction & Management, Inc., a property management company, and a director of TRM Corporation, a publicly traded consumer services company. Mr. Cohen is the father of Jonathan Z. Cohen.

Jonathan Z. Cohen has been the President of Resource America since 2003, Chief Executive Officer of Resource America since 2004 and a director since 2002. He was the Chief Operating Officer of Resource America from 2002 to 2004 and Executive Vice President of Resource America from 2001 until 2003. Before that, Mr. Cohen had been a Senior Vice President since 1999. Mr. Cohen has been Vice Chairman of Atlas America since its formation in 2000. Mr. Cohen has also served as Trustee and Secretary of RAIT Investment Trust, a publicly-traded real estate investment trust, since 1997, Vice Chairman of RAIT since 2003 and Chairman of the Board of Directors of The Richardson Company, a sales consulting company, since 1999. Mr. Cohen is the son of Edward E. Cohen.

Michael L. Staines was Senior Vice President of Resource America from 1989 to May 2004 and served as a director from 1989 through 2000 and Secretary from 1989 through 1998. Since its formation in 2000, Mr. Staines has been an Executive Vice President of Atlas America. Mr. Staines is a member of the Ohio Oil and Gas Association, the Independent Oil and Gas Association of New York and the Independent Petroleum Association of America.

Freddie M. Kotek has been an Executive Vice President and Chief Financial Officer of Atlas America since February 2004 and served as a director from September 2001 until February 2004. Mr. Kotek has been Chairman of Atlas Resources, Inc., Atlas America's wholly-owned subsidiary which acts as the managing partner of its drilling investment partnerships, since September 2001 and Chief Executive Officer and President of Atlas Resources since January 2002. He was a Senior Vice President of Resource America from 1995 to May 2004.

Tony C. Banks has been the Director of Marketing for First Energy Solutions Corp, a public utility, since 2004. Prior thereto, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through early 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the Board of Optiron Corporation, which was an energy technology subsidiary of Atlas America until 2002. In addition, Mr. Banks served as President of our general partner during 2000. He was Chief Executive Officer and President of Atlas America from 1998 through 2000.

Michael J. Bradley has been a co-owner and Managing Director of BF Healthcare, Inc., a supplier of physician services to hospitals and assisted living facilities, since 1994. Mr. Bradley has served on the board of directors of SourceCorp., a provider of business process outsourcing solutions to the healthcare, legal, financial services, government, transportation and logistics industries, since 1996. From 1988 to 1998, Mr. Bradley served as Chairman of First Executive Bank, and from 1998 to 2003 he served as Vice Chairman of First Republic Bank. From 1994 through 1997, Mr. Bradley was Executive Vice President of Mercy Health Corporation of Southeast Pennsylvania. Mr. Bradley is a certified public accountant and holds a B.S. in Business Administration from Drexel University.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Mr. Clifford has 37 years' experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and consulting. He has been president of Amity Manor, Inc. since 1988 when he founded the company to develop housing for low-income elderly using tax credit financing. Mr. Clifford holds bachelor degrees in Civil Engineering and Social Science from Union College, Schenectady NY and is a registered professional engineer in Pennsylvania.

Murray S. Levin is a senior litigation partner at Pepper Hamilton LLP. Mr. Levin served as the first American President of the Association Internationale des Jeunes Avocats (Young Lawyers International Association), headquartered in Western Europe. He is a past president of the American Chapter and a member of the board of directors of the Union Internationale des Avocats (International Association of Lawyers), a Paris-based organization that is the world's oldest international lawyers association.

OTHER SIGNIFICANT EMPLOYEES

Nancy J. McGurk, 49, has been the Chief Accounting Officer of our general partner since 1999. Ms. McGurk had been Vice President of Resource America from 1992 and Treasurer and Chief Accounting Officer from 1989 to May 2004.

Robert F. Firth, 50, has been the President and Chief Executive Officer of Spectrum (acquired by us in July 2004) and now known as Atlas Pipeline Mid-Continent LLC) since 2002. From 1999 to 2002, Mr. Firth served as Vice President, Operations and Commercial Services at ScissorTail Energy. Mr. Firth has 30 years experience in the midstream gas industry.

David D. Hall, 47, has been the Executive Vice President and Chief Financial Officer of Spectrum (acquired by us in July 2004) and now known as Atlas Pipeline Mid-Continent LLC) since 2002. From 2000 to 2002, Mr. Hall served as a senior business analyst at ScissorTail Energy. Mr. Hall has more than 25 years experience as a financial executive in the energy industry.

Daniel C. Herz, 28, has been an employee of Atlas America since January 2004 where he now serves as Vice President of Corporate Development. Mr. Herz was an Associate Investment Banker with Banc of America Securities from 2002 to 2003 and an Analyst from 1999 to 2002. Mr. Herz graduated with a BA in economics from Indiana University in 1999.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and managing board members of our general partner and persons who own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports. Based solely upon our review of reports received by us, or representations that no filings were required, we believe that all of the officers and managing board members of our general partner complied with all applicable filing requirements during 2004, except for one Form 4 inadvertently filed late by each of Messrs. Banks and Levin in connection with a grant under our long-term incentive plan. We did not have any record holders of 10% or more of our common units in 2004.

REIMBURSEMENT OF EXPENSES OF OUR GENERAL PARTNER AND ITS AFFILIATES

Our general partner does not receive any management fee or other compensation for its services apart from its general partner and incentive distribution interests. We reimburse our general partner and its affiliates, including Atlas, for all expenses incurred on our behalf. These expenses include the costs of employee, officer and managing board member compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Our general partner allocates the costs of employee and officer compensation and benefits based upon the amount of business time spent by those employees and officers on our business. We reimbursed our general partner $15.9 million for expenses incurred and capitalized costs during 2004, which constituted all of our transportation and compression, general and administrative costs in our Appalachian area of operations.

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COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

Neither we nor the managing board of our general partner has a compensation committee. Compensation of the personnel of Atlas America and its affiliates who provide us with services is set by Atlas America and such affiliates. The independent members of the managing board of our general partner, however, do review the allocation of the salaries of such personnel for purposes of reimbursement, discussed in "Reimbursement of Expenses of our General Partner and Its Affiliates", above and in Item 11, "Executive Compensation." None of the independent managing board members is an employee or former employee of ours or of our general partner. No executive officer of our general partner is a director or executive officer of any entity in which an independent managing board member is a director or executive officer.

CODE OF BUSINESS CONDUCT AND ETHICS

We have adopted a Code of Business Conduct and Ethics that applies to the principal executive officer, principal financial officer and principal accounting officer of our general partner, as well as to persons performing services for us generally. This code of ethics is posted on our website at:

www.atlaspipelinepartners.com.

ITEM 11. EXECUTIVE COMPENSATION

EXECUTIVE COMPENSATION

We do not directly compensate the executive officers of our general partner. Rather, Atlas America and its affiliates allocate the compensation of the executive officers between activities on behalf of our general partner and us and activities on behalf of itself and its affiliates based upon an estimate of the time spent by such persons on activities for us and for Atlas America and its affiliates. We reimburse our general partner for the compensation allocated to us. The compensation allocation was $1,081,000, $1,035,000 and $438,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The following table sets forth the compensation allocation for the last three fiscal years for our general partner's Chief Executive Officer and President. No other executive officer of the general partner received an allocation of aggregate salary and bonus in excess of $100,000 during the periods indicated.

SUMMARY COMPENSATION TABLE

NAME AND PRINCIPAL POSITION	YEAR	SALARY	
Edward E. Cohen, Chairman of the Managing Board and Chief Executive Officer	2004	$ 133,950	$
	2003	179,600	
	2002	0	
Michael L. Staines, President, Chief Operating Officer and Managing Board Member	2004	$ 219,400	$
	2003	133,300	
	2002	169,979	

(1) See "Long-Term Incentive Plan"

LONG-TERM INCENTIVE PLAN

Our general partner has adopted the Atlas Pipeline Partners, L.P. Long-Term Incentive Plan (the "Plan") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the Plan include phantom units and unit options. The Plan currently permits the grant of phantom units and unit options covering an aggregate of 435,000 common units delivered upon vesting of such phantom units or unit options. The Plan is administered by a committee appointed by the General Partner's managing board (the "Committee"), which sets the terms of awards under the Plan. The Committee may make awards of either phantom units or options for an aggregate of 435,000 common units, provided that the maximum number of phantom units that may be awarded in total to non-employee managing board members is 10,000.

Phantom Units. A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2004, grants of 58,752 unvested phantom units under the Plan remain outstanding to employees, officers and directors of our general partner. The Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Committee shall determine, including tandem distribution equivalent rights with respect to phantom units. As a result of the vesting of these awards, we recognized an expense of $700,000 during 2004.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon receipt of the common units.

Grants of 1,752 phantom units were made in 2004 to current non-employee directors of our general partner. These units vest and are payable in 25%

increments.

The following table shows the vesting of phantom units granted under the Plan during 2004 to the Named Executive Officers.

NAME	TOTAL UNITS	REMAINING UNVESTED GRANTS (1) UNITS	REMAINING UNVESTED GRANTS (1) VALUE
Edward E. Cohen	25,000	25,000	$ 1,047,500
Michael L. Staines	8,000	8,000	$ 335,200

(1) As if vested on December 31, 2004, at a market closing price of $41.90 per unit.

COMPENSATION OF MANAGING BOARD MEMBERS

Our general partner does not pay additional remuneration to officers or employees of Atlas America who also serve as managing board members. In fiscal year 2004 Each non-employee managing board member received an annual retainer of $20,000 in cash and an annual grant of phantom units (1) with DERs (2) in an amount equal to the lesser of 500 units or $15,000 worth of units (based upon the market price of our common units) pursuant to our Long-Term Incentive Plan, which was approved by our unitholders on February 11, 2004. In addition, our general partner reimburses each non-employee board member for out-of-pocket expenses in connection with attending meetings of the board or committees. We reimburse our general partner for these expenses and indemnify our general partner's managing board members for actions associated with serving as managing board members to the extent permitted under Delaware law.

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(1) A phantom unit is one which, upon vesting, entitles the holder to receive a common unit or its then fair market value in cash, as specified in the grant.

(2) A right, granted in tandem with a specific phantom unit, to receive an amount in cash equal to, and at the same time as, the cash distributions made by us on our outstanding common units.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the number and percentage of our common units held by beneficial owners of 5% or more of either our common or subordinated units, by executive officers and members of the managing board of our general partner and by all of the executive officers and managing board members of our general partner as a group as of March 1, 2005. The address of our general partner, its executive officers and managing board members is 311 Rouser Road, Moon Township, Pennsylvania 15108.

NAME OF BENEFICIAL OWNER	COMMON UNITS	PERCENT OF CLASS
Atlas Pipeline Partners GP...........	1,641,026	23%
Edward E. Cohen......................	4,100	-*
Jonathan Z. Cohen....................	3,977	-*
Michael L. Staines...................	-	-
Freddie M. Kotek.....................	600	-*
Michael J. Bradley...................	-	-
Curtis D. Clifford...................	-	-

Tony C. Banks........................	-	-
Murray S. Levin......................	-	-
Executive officers and managing board members as a group (8 persons)......	1,649,703	23%

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* Less than 1%.

EQUITY COMPENSATION PLAN INFORMATION

The following table contains information about our equity compensation plans as of December 31, 2004:

	(A)	(B)	
PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF PHANTOM UNITS,	WEIGHTED-AVERAGE EXERCISE PRICE OF OUTSTANDING PHANTOM UNITS	NUMBER OF AVAILABL UNDER EQU (EXCLUDIN I
Equity compensation plans approved by security holders	58,752	$0	

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

At December 31, 2004, our general partner owned 1,641,026 subordinated units constituting 23% of the limited partner interest in us. Our general partner also owns, through its 1.0101% general partnership interest in us and 1.0101% general partnership interest in our operating subsidiary, Atlas Pipeline Operating Partnership, a 2% general partner interest in our consolidated pipeline operations. We paid our general partner distributions totaling $6.4 million in 2004 in respect of these interests.

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

In connection with the acquisition of Spectrum described in Item 1, "Business - General," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations", we entered into commitment agreements with Resource America and Atlas America for the purchase by them of up to $25.0 million of preferred units in Atlas Pipeline Operating Partnership, L.P., our subsidiary. In consideration for their commitments, upon the closing of the Spectrum acquisition and the purchase by each of $10.0 million preferred units, we paid Resource America and Atlas America commitment fees of $750,000 and $500,000, respectively.

In connection with the proposed acquisition of Alaska Pipeline Company, L.L.C. we paid Resource America a fee of $70,750 in the year ended December 31, 2004 for its commitment to repay certain financing that would have been required to complete the acquisition.

We do not currently directly employ any persons to manage or operate our business. These functions are provided by employees of Atlas America and/or its affiliates. As discussed in Items 10 and 11, we reimburse our general partner, Atlas America and its affiliates for expenses they incur in managing our operations and for an allocation of the compensation paid to the executive officers of our general partner.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ending December 31, 2004 and 2003 by its principal accounting firm, Grant Thornton LLP are set forth below.

	2004	2003
Audit fees (1)	$ 399,732	$ 89,100
Audit related fees (2)	-	-
Tax fees (3)	362,309	47,000
All other fees (4)	152,363	237,600
Total aggregate fees billed	$ 914,404	$ 373,700

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

(2) There were no aggregate fees billed in each of the last two years for assurance and related services by Grant Thornton LLP that are reasonably related to the performance of the audit or review of our financial statements.

(3) Includes the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for tax compliance, tax advice, and tax planning.

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

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES

Pursuant to its charter, the audit committee of the managing board of our general partner is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. All of such services and fees were pre-approved during 2004.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

(A)(2) FINANCIAL STATEMENT SCHEDULES
No schedules are required to be presented.

(A)(3) EXHIBITS

Exhibit No.	Description
3.1	Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Partners, L.P. (1)
3.2	Certificate of Limited Partnership of Atlas Pipeline Partners, L.P. (1)
4.1	Common unit certificate. (1)
10.1	First Amendment to Revolving Credit and Term Loan Agreement, dated December 3, 2004, among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association, et al.
21.1	Subsidiaries of Atlas Pipeline Partners, L.P.
23.1	Consent of Grant Thornton LLP.
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

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(1) Filed previously as an exhibit to our Registration Statement on Form S-1 (Registration No. 333-85193) and by this reference incorporated herein.

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SIGNATURES

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

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

March 16, 2005 By: /s/ Edward E. Cohen

Chairman of the Managing Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of March 16, 2004.

/s/ Edward E. Cohen EDWARD E. COHEN	Chairman of the Managing Board of the General Partner Chief Executive Officer of the General Partner
/s/ Jonathan Z. Cohen JONATHAN Z. COHEN	Vice Chairman of the Managing Board of the General Partn
/s/ Michael L. Staines MICHAEL L. STAINES	President, Chief Operating Officer, Managing Board Member of the General Partner
/s/ Freddie M. Kotek FREDDIE M. KOTEK	Chief Financial Officer of the General Partner
/s/ Nancy J. McGurk NANCY J. McGURK	Chief Accounting Officer of the General Partner
/s/ Tony C. Banks TONY C. BANKS	Managing Board Member of the General Partner
/s/ Michael J.Bradley MICHAEL J. BRADLEY	Managing Board Member of the General Partner
/s/ Curtis D. Clifford CURTIS D. CLIFFORD	Managing Board Member of the General Partner
/s/ Murray S. Levin MURRAY S. LEVIN	Managing Board Member of the General Partner