ATLAS PIPELINE PARTNERS LP
Form 424B5
November 22, 2005
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File Number 333-127961

PROSPECTUS SUPPLEMENT

(To Prospectus dated August 30, 2005)

ATLAS PIPELINE PARTNERS, L.P.

2,700,000 Common Units

Representing Limited Partner Interests

We are offering 2,700,000 of our common units representing limited partner interests. Our common units trade on the New York Stock Exchange under the symbol APL. The last reported sales price of our common units on the New York Stock Exchange on November 21, 2005 was $42.00 per common unit.

Investing in our common units involves risks. See Risk Factors beginning on page S-14 of this prospectus supplement and on page 1 of the accompanying prospectus.

	Per Common Unit	Total
Public offering price	$42.00	$113,400,000
Underwriting discount	$ 1.89	$ 5,103,000
Proceeds to us (before expenses)	$40.11	$108,297,000

We have granted the underwriters a 30-day option to purchase up to an additional 405,000 common units on the same terms and conditions as set forth above if the underwriters sell more than 2,700,000 common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Lehman Brothers, on behalf of the underwriters, expects to deliver the common units on or about November 28, 2005.

LEHMAN BROTHERS

Sole Book-Running Manager

CITIGROUP

A.G. EDWARDS

FRIEDMAN BILLINGS RAMSEY

WACHOVIA SECURITIES

KEYBANC CAPITAL MARKETS **SANDERS MORRIS HARRIS**

November 21, 2005

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This document is in two parts. The first part is this prospectus supplement, which describes our business and the terms of this offering of common units. The second part is the accompanying prospectus, which gives more general information, some of which may not apply to this offering of common units. If information varies between this prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

You should rely only on the information contained in or incorporated by reference into this prospectus supplement or the accompanying prospectus. We have not authorized anyone to provide you with different information.

We are not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information contained in this prospectus supplement or the accompanying prospectus is accurate as of any date other than the dates shown in these documents or that any information we have incorporated by reference is accurate as of any date other than the date of the document incorporated by reference. Our business, financial condition, results of operations and prospects may have changed since those dates.

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NOTE ABOUT CERTAIN TERMS USED IN THIS PROSPECTUS SUPPLEMENT

In this prospectus supplement, unless the context indicates otherwise:

- the terms the Partnership, we, our and us refer to Atlas Pipeline Partners, L.P. and its subsidiaries;
- the term our general partner refers to Atlas Pipeline Partners GP, LLC, a wholly-owned subsidiary of Atlas America, Inc., which we refer to as Atlas America ;
- we refer to natural gas liquids, such as ethane, propane, normal butane, isobutane and natural gasoline, as NGLs ;
- we refer to billion cubic feet as Bcf, million cubic feet as MMcf, thousand cubic feet as Mcf, million cubic feet per day as MMcf/d ar thousand cubic feet per day as Mcf/d ;
- we refer to barrels as Bbls and barrels per day as Bbls/d ;
- we refer to the Federal Energy Regulatory Commission as FERC ;
- we refer to million British Thermal Units as MMbtu and million British Thermal Units per day as MMbtu/d ; and
- the information presented assumes that the underwriters do not exercise their option to purchase an additional 405,000 common units.

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SUMMARY

This summary highlights information contained elsewhere in this prospectus supplement and in the accompanying prospectus. You should read the entire prospectus supplement, the accompanying prospectus, the documents incorporated by reference and the other documents to which we refer for a more complete understanding of this offering. You should read Risk Factors beginning on page S-13 of this prospectus supplement and on page 1 of the accompanying prospectus for more information about important factors that you should consider before buying common units in this offering.

Atlas Pipeline Partners, L.P.

We are a publicly-traded midstream energy services provider engaged in the transmission, gathering and processing of natural gas. We conduct our business through two operating segments: our Mid-Continent operations and our Appalachian operations.

We own and operate through our Mid-Continent operations:

- a 75% interest in a FERC-regulated, 565-mile interstate pipeline system, which we refer to as Ozark Gas Transmission, that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 322 MMcf/d;
- two natural gas processing plants with aggregate capacity of approximately 230 MMcf/d and one treating facility with a capacity of approximately 200 MMcf/d, both located in Oklahoma; and
- 1,765 miles of active natural gas gathering systems located in Oklahoma, Arkansas, northern Texas and the Texas panhandle, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or Ozark Gas Transmission.

We own and operate through our Appalachian operations 1,500 miles of active natural gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Through an omnibus agreement and other agreements between us and Atlas America, the parent of our general partner and a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin, we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas America. Among other things, the omnibus agreement requires Atlas America to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport. These agreements are continuing obligations and have no specified term except that they will terminate if our general partner is removed without cause.

Since our initial public offering in January 2000, we have completed five acquisitions at an aggregate cost of approximately $516.7 million, including, most recently, our October 2005 acquisition of Atlas Arkansas Pipeline LLC, which owns a 75% interest in NOARK Pipeline System, Limited Partnership, which we refer to as NOARK, and our April 2005 acquisition of ETC Oklahoma Pipeline, Ltd, which we refer to as Elk City.

Both our Mid-Continent and Appalachian operations are located in areas of abundant and long-lived natural gas production and significant new drilling activity. The Ozark Gas Transmission system and our gathering systems are connected to approximately 6,250 central delivery points or wells, giving us significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. We provide fee-based, FERC-regulated transmission services through Ozark Gas Transmission under both long-term and short-term contractual arrangements. We intend to increase the portion of the transmission services provided under long-term contracts. As a result of the location and capacity of the Ozark Gas Transmission system and our gathering and processing assets, we believe we are strategically

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positioned to capitalize on the significant increase in drilling activity in our service areas and the positive price differential across Ozark Gas Transmission, also known as basis spread. We intend to continue to expand our business through strategic acquisitions and organic growth projects, including our recently announced plan to construct the Sweetwater gas plant, that increase distributable cash flow per unit.

The following table shows the pro forma gross margin for our operating units for the periods indicated:

	Pro forma			
	Year ended December 31, 2004		Nine months ended September 30, 2005	
	$	%	$	%
Mid-Continent				
Velma and Elk City	$ 43,294	51.2%	$ 37,757	53.0%
NOARK	22,480	26.6%	16,940	23.8%
	65,774	77.8%	54,697	76.8%
Appalachia	18,800	22.2%	16,501	23.2%
	$ 84,574	100.0%	$ 71,198	100.0%

Please see Summary Historical Consolidated and Other Financial Data for a definition of gross margin and a reconciliation of pro forma gross margin to our pro forma net income.

Recent Developments

Recent Distribution Increase. On October 27, 2005, we declared a quarterly cash distribution of $0.81 per common unit for the quarter ended September 30, 2005, payable on November 14, 2005 to holders of record as of November 7, 2005. This represents a 17.4% increase from the cash distribution of $0.69 for the quarter ended September 30, 2004.

Acquisition of Atlas Arkansas and Controlling Interest in NOARK. On October 31, 2005, we acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), which we refer to as Enogex, all of the outstanding equity of Atlas Arkansas Pipeline LLC, which we refer to as Atlas Arkansas and which owns a 75% interest in NOARK, for $165.3 million, including estimated related transaction costs, plus $10.2 million for working capital adjustments. We refer to this acquisition as the NOARK acquisition. The remaining 25% interest in NOARK is owned by Southwestern Energy Pipeline Company, which we refer to as Southwestern, a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Before the closing of our acquisition, Atlas Arkansas converted from an Oklahoma corporation into an Oklahoma limited liability company and changed its name from Enogex Arkansas Pipeline Company. The NOARK acquisition further expands our activities in the Mid-Continent region and provides an additional source of fee-based cash flows from a FERC-regulated interstate pipeline system and an intrastate gas gathering system. NOARK s geographic position relative to our other businesses and interconnections with major interstate pipelines also provides us with organic growth opportunities. NOARK s principal assets include:

The Ozark Gas Transmission system, a 565-mile FERC-regulated interstate pipeline system which extends from southeast Oklahoma through Arkansas and into southeast Missouri and has a throughout capacity of approximately 322 MMcf/d. The system includes approximately 30 supply and delivery interconnections and two compressor stations.

A 365-mile intrastate natural gas gathering system, which we refer to as Ozark Gas Gathering, located in eastern Oklahoma and western Arkansas, and 11 associated compressor stations.

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We financed the acquisition by borrowing under our senior secured credit facility. We intend to use all of the net proceeds from this offering to repay a portion of the balance outstanding under our credit facility. We expect the NOARK acquisition to be immediately accretive to our distributable cash flow per unit.

Ozark Gas Transmission transports natural gas from receipt points in eastern Oklahoma and western Arkansas, where the Arkoma Basin is located, to interstate pipelines in northeastern and central Arkansas and to local distribution companies in Arkansas and Missouri. Ozark Gas Gathering provides access to natural gas supplies that are then transported through Ozark Gas Transmission. Ozark Gas Transmission s revenues are comprised of FERC-regulated transmission fees that are based on firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates. The Ozark transmission and gathering systems transported an average of 163.9 MMcf/d during the nine months ended September 30, 2005, and 207.2 MMcf/d during October 2005.

The NOARK acquisition increases our size and presence in the Mid-Continent region, including extending our operations east into the Arkoma Basin. The Mid-Continent region, one of the most prolific natural gas-producing regions in North America, has recently experienced a significant increase in oil and gas drilling activity driven by long-term projections of continued growth in U.S. natural gas demand and the application of new drilling and production technologies. For example, the average monthly drilling rig count in Oklahoma during 2005 through October was 153, a 19% increase over the average monthly drilling rig count in 2003 of 129. Ozark Gas Gathering accesses the Fayetteville Shale Play, located in the Arkoma Basin. Southwestern Energy Company, an active driller in the area, has announced that it expects to drill between 175 to 200 wells in the Fayetteville Shale Play in 2006. Southwestern Energy Company also recently announced the purchase of ten drilling rigs which it expects to be delivered monthly beginning in November 2005 for use in the Play. In developing its Fayetteville Shale acreage, Southwestern Energy Company announced on October 27, 2005 that it has drilled 67 wells to date in ten different areas. Southwestern Energy Company has announced that it expects to further evaluate its Fayetteville Shale acreage over the next 12-15 months by drilling an additional 35 to 40 wells.

Amended Credit Facility. In conjunction with the acquisition of Elk City in April 2005, we entered into a new $270.0 million credit facility with a bank syndicate led by Wachovia Bank, National Association and Bank of America N.A. The facility consisted of a $225.0 million five-year revolving loan and a $45.0 million five-year term loan. We repaid and retired the term loan in June 2005. In connection with the NOARK acquisition, the revolving credit facility was increased to a maximum of $400.0 million. As of November 21, 2005, there was $361.5 million of outstanding debt on the facility.

New Construction. We recently completed three new gathering and compression projects in Elk City which will increase gathered volumes and total gross margin. We also plan to complete construction of a new natural gas processing facility in Oklahoma near our Prentiss treating facility by mid-2006, which we refer to as the Sweetwater plant. The new plant will be scaled to 120 MMcf/d of processing capacity. Along with the plant, we will construct a gathering system to be located primarily in western Oklahoma and in the Texas panhandle, more specifically, Beckham and Roger Mills counties in Oklahoma and Hemphill County, Texas. We anticipate that construction of the plant and associated gathering system will cost approximately $40.0 million and will generate cash flow of $8.0 million to $10.0 million annually.

Acquisition of Elk City. In April 2005, we acquired all of the outstanding equity interests in Elk City for $196.0 million, including related transaction costs. Elk City s principal assets include approximately 300 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, a natural gas processing facility in Elk City, Oklahoma, with a total capacity of approximately 130 MMcf/d, and a gas treating facility in Prentiss, Oklahoma, with a total capacity of approximately 200 MMcf/d. Gathered volumes averaged 242.3 MMcf/d for the nine months ended September 30, 2005. The system connects to over 300 receipt points. The acquisition expanded the scale of our Mid-Continent operations and built upon our experience in processing and gathering.

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Updated Hedging Positions. In our Mid-Continent operations, we have hedged portions of our natural gas, NGLs and condensate volumes for fixed prices for various periods through 2008. The following table summarizes our hedge positions through December 31, 2006:

Commodity	Average percentage of anticipated volumes hedged	Average fixed price
Natural gas	48%	$6.55/MMbtu
NGLs	54%	$0.68/gallon
Condensate	62%	$49.51/Bbl

In our Appalachian operations, we are the beneficiary of, and consult with Atlas America with respect to, the hedging program Atlas America has established for its Appalachian natural gas production.

Proposed High Yield Debt Offering. We intend to sell in a private placement, subject to market conditions, up to $250.0 million in aggregate principal amount of senior unsecured notes. The notes will not be registered under the Securities Act or any state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from registration. We expect that the notes will be offered only to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. We anticipate that we will use the net proceeds from the offering to repay borrowings under our credit facility.

Possible Public Offering by Our General Partner. Atlas America has recently announced that it is considering transferring its ownership interest in our general partner to a new wholly-owned subsidiary and then making a registered initial public offering of a minority interest in the subsidiary. **This prospectus supplement does not constitute an offer to sell or a solicitation of an offer to buy any such securities. Please see Risk Factors Risks Inherent in an Investment in Us If Atlas America proceeds with a public offering of securities in an entity that owns our general partner, it may affect the relative attractiveness of an investment in our common units for a discussion of the risks to our unitholders of such an offering.**

Business Strategy

Our primary objective is to increase distributable cash flow per unit and returns to our unitholders by:

- maximizing cash flows from our existing businesses through marketing of our services and facilities and controlling our operating costs;
- continuing to increase the amount of our operating cash flow generated by long-term, fee-based contracts;
- expanding our existing businesses through organic growth opportunities;
- expanding our operations through strategic acquisitions; and

maintaining a flexible capital structure based on a strong balance sheet by financing our growth through a balanced combination of debt and equity.

Competitive Strengths

We believe we are well-positioned to successfully execute our business strategy because of the following competitive strengths:

Strategically positioned for organic growth. We are a leading provider of transportation and natural gas gathering services in the Anadarko Basin and the Arkoma Basin, the Golden Trend area of Oklahoma and the Appalachian Basin and of natural gas processing services in Oklahoma. We expect the breadth of our operations in our service areas, our customer focus and our relationship with Atlas

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America will allow us to continue to connect new wells and capture new natural gas volumes quickly and cost-effectively. Additionally, the NOARK acquisition increases our size and presence in the Mid-Continent region, including expanding our operations east into the Arkoma Basin.

Diversified asset base. Our operations are divided between the active Mid-Continent Basin, including Arkansas, Oklahoma, southern Missouri, northern Texas and the Texas panhandle, where we transport, gather, process and treat third-party gas volumes, and the Appalachian Basin, where we access new volumes through long-term gathering agreements with Atlas America. In addition, our revenues are generated under a variety of contract structures, including FERC-regulated transmission fees from Ozark Gas Transmission, fixed fees from our gathering and treating businesses, percentage-of-proceeds contracts from our gathering and processing businesses and, to a lesser extent, keep-whole contracts from our Elk City processing plant, which we may bypass during periods of unfavorable processing margins.

Stability from long-term contracts and strong customer relations. Our gas supply strategy in the Mid-Continent region is to establish long-term, value-oriented relationships with our producing customers. We have long-standing relationships with many of our Mid-Continent customers which account for a substantial majority of our gathering and processing throughput. Ozark Gas Transmission also has strong relationships with numerous shippers that contract for transmission services either on a short or long-term firm basis or interruptible basis. In addition, our Appalachian operations generate substantially all of their volumes under a long-term omnibus agreement with Atlas America whereby Atlas America is required to commit to our gathering system all wells it drills and operates that are within 2,500 feet of the system. Wells under this agreement are committed for the life of their respective leases, typically over 30 years.

Relationship with Atlas America. As a result of our agreements with Atlas America, we believe that the growth in the number of wells drilled by Atlas America and its affiliates in the Appalachian Basin will serve as an engine for our growth in the region. We connected 411 Atlas America wells to our Appalachian gathering system for the twelve months ended September 30, 2005, and 1,508 Atlas America wells from our inception in January 2000 through September 30, 2005.

Efficient assets which offer low maintenance capital expenditure requirements, system flexibility and superior customer service. Our transmission, gathering and processing systems carry low maintenance capital expenditure needs. In addition, a significant portion of our existing gathering systems and processing plants are new or have been recently expanded or replaced. Our gathering systems provide our customers increased flexibility through low pressure service and multiple pipeline interconnections, and our willingness to expand our systems quickly provides our customers with superior customer service.

Favorable commercial agreements that reduce commodity price risk. We derive substantially all of the operating income from our gathering and processing operations from fee-based and percentage-of-proceeds arrangements. We have hedged a significant amount of our near-term equity natural gas production and equity NGL production from our processing operations, which we believe should reduce volatility in our operating income. Furthermore, we can bypass our Elk City processing plant during periods of unfavorable processing margins. Substantially all of the operating income generated by NOARK s transmission and gathering assets is generated under fixed-fee agreements. In our Appalachian operations, we are the beneficiary of, and consult with Atlas America with respect to, the hedging program Atlas America has established for its Appalachian natural gas production that mitigates the risks of our percentage-of-proceeds agreement with it.

Experienced management and engineering team. Through our general partner we have significant management and technical expertise. Our senior management team averages approximately 20 years of experience in the oil and natural gas industry and currently manages 91 public and private drilling investment partnerships. Our operational and technical expertise has enabled us to identify assets that have not been fully utilized and to improve their performance upon integration into our operations.

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Our Organizational Structure

We conduct our operations through, and our operating assets are owned by, our subsidiaries. Our general partner has sole responsibility for conducting our business and managing our operations. Our general partner does not receive any management fee or other compensation in connection with its management of our business apart from its general partner interest and incentive distribution rights, but it is reimbursed for direct and indirect expenses incurred on our behalf. Our principal executive offices are located at 311 Rouser Road, Moon Township, Pennsylvania 15108 and our telephone number is (412) 262-2830. The following diagram depicts our organizational structure and ownership after giving effect to this offering:

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The Offering

Common units offered	2,700,000 common units.
	3,105,000 common units if the underwriters exercise their option to acquire an additional 405,000 common units.
Units outstanding after this offering	12,219,266 common units.
	12,624,266 common units if the underwriters exercise their option to acquire an additional 405,000 common units.
Use of proceeds	We will use all of the net offering proceeds, which we estimate will be $110.0 million, including a $2.3 million capital contribution from our general partner, after deducting underwriting discounts, commissions and estimated offering expenses of $5.7 million, to reduce outstanding indebtedness under our credit facility. Certain affiliates of three of the underwriters in this offering are lenders under our credit facility. For more information, please read Use of Proceeds and Underwriting Relationships.
Cash distribution policy	We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner in its discretion. The amount of this cash may be greater than or less than the minimum quarterly distribution referred to in the next paragraph. We generally make cash distributions within 45 days after the end of each quarter.
	When quarterly cash distributions exceed $0.42 per unit in any quarter, our general partner receives a higher percentage of the cash distributed in excess of that amount, in increasing percentages up to 50% if the quarterly cash distribution exceeds $0.60 per unit. We refer to our general partner s right to receive these higher amounts of cash as incentive distribution rights.
	For a discussion of our cash distribution policy, please read Our Partnership Agreement Cash Distribution Policy in the accompanying prospectus.
	On October 27, 2005 we declared a quarterly cash distribution of $0.81 per common unit for the quarter ended September 30, 2005, payable on November 14, 2005 to holders of record as of November 7, 2005. Since the distribution will exceed $0.42, our general partner will receive an incentive distribution.
Ratio of taxable income to distributions	We estimate that if you purchase common units in this offering and own them through December 31, 2007, you will be allocated an amount

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	of federal taxable income for that period which is less than 20% of the cash we expect to distribute for that period. We anticipate that, for taxable years beginning after December 31, 2007, the taxable income allocable to you will represent a higher percentage of cash distributed to you. Please read Tax Considerations Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions in this prospectus supplement for an explanation of the basis of this estimate.
New York Stock Exchange symbol	APL.

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Summary Historical Consolidated and Other Financial Data

The following table sets forth selected consolidated financial data as of and for each of the three years ended December 31, 2002, 2003 and 2004 and the nine months ended September 30, 2004 and 2005. We derived the financial data for each of the years ended December 31, 2002, 2003 and 2004 and at December 31, 2003 and 2004 from our consolidated financial statements incorporated by reference in this prospectus supplement, which have been audited by Grant Thornton LLP, independent registered accountants. We derived the financial data as of and for the nine months ended September 30, 2004 and 2005 from our unaudited consolidated financial statements incorporated by reference in this prospectus supplement.

We have also included unaudited pro forma financial data that reflects our historical results as adjusted on a pro forma basis to give effect to our April 2004, July 2004 and June 2005 offerings of common units, the completion of the NOARK acquisition and the acquisitions of Spectrum Field Services, Inc., which we refer to as Spectrum, and Elk City, and this offering.

The unaudited pro forma balance sheet information reflects the following transactions as if they occurred as of September, 30, 2005:

- the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs;
- the increase in our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition; and
- this offering and the application of the net proceeds as described under Use of Proceeds.

The unaudited pro forma statement of income information for the year ended December 31, 2004 reflects the following transactions as if they occurred as of January 1, 2004:

- the Spectrum acquisition, which occurred in July 2004, for total consideration of $141.6 million, including the payment of income taxes due as a result of the transaction and other related transaction costs;
- the Elk City acquisition, which occurred in April 2005, for total consideration of $196.0 million, including related transaction costs;
- the closing of our $270.0 million credit facility, which occurred in April 2005, and borrowings under it to finance the Elk City acquisition and repay amounts outstanding under our previous credit facility;
- the increase of our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition;

our public offering of 2,100,000 common units, which was completed in July 2004 at a public offering price of $34.76 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were used principally to repay indebtedness incurred in connection with the Spectrum acquisition;

our public offering of 2,300,000 common units, which was completed in June 2005 at a public offering price of $41.95 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were used principally to repay indebtedness incurred in connection with the Elk City acquisition;

the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs, and the redemption of the portion of the NOARK 7.15% notes severally guaranteed by Atlas Arkansas; and

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this offering and the application of the net proceeds as described under Use of Proceeds.

The unaudited pro forma statement of income information for the nine months ended September 30, 2005 reflects the following transactions as if they occurred as of January 1, 2005:

the Elk City acquisition, which occurred in April 2005, for total consideration of $196.0 million, including related transaction costs;

the closing of our $270.0 million credit facility, which occurred in April 2005, and borrowings under it to finance the Elk City acquisition and repay amounts outstanding under our previous credit facility;

the increase of our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition;

our public offering of 2,300,000 common units, which was completed in June 2005, at a public offering price of $41.95 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were principally used to repay indebtedness incurred in connection with the Elk City acquisition;

the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs, and the redemption of the portion of the NOARK 7.15% notes severally guaranteed by Atlas Arkansas; and

this offering and the application of the net proceeds as described under Use of Proceeds.

Elk City s historical fiscal year ended August 31, 2004 is not within 93 days of our fiscal year end. Accordingly, for pro forma purposes, statement of income information for the year ended December 31, 2004 is based on Elk City s historical financial results for the twelve months ended November 30, 2004 and was created by subtracting the quarter ended November 30, 2003 from Elk City s income statement for the year ended August 31, 2004 and adding the quarter ended November 30, 2004. For our pro forma statement of income information for the nine months ended September 30, 2005, we included Elk City s income statement for the three months ended February 28, 2005. Elk City was included within our historical results for the nine months ended September 30, 2005 from its date of acquisition on April 14, 2005.

The unaudited pro forma balance sheet and the pro forma statements of income were derived by adjusting our historical financial statements. However, our management believes that the adjustments provide a reasonable basis for presenting the significant effects of the transactions described above. The unaudited pro forma financial data presented are for informational purposes only and are based upon available information and assumptions that we believe are reasonable under the circumstances. You should not construe the unaudited pro forma financial data as indicative of the combined financial position or results of operations that we, Spectrum, Elk City and NOARK would have achieved had the transactions been consummated on the dates assumed. Moreover, they do not purport to represent our, Spectrum s, Elk City s or NOARK s combined financial position or results of operations for any future date or period.

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The financial data below should be read together with, and are qualified in their entirety by reference to, our historical consolidated and pro forma combined financial statements and the accompanying notes, Management s Discussion and Analysis of Financial Condition and Results of Operations, and the historical consolidated financial statements and the accompanying notes of Elk City and its predecessor and Enogex Arkansas Pipeline, each of which is set forth elsewhere or incorporated by reference in this prospectus supplement. The pro forma data are not necessarily reflective of what our results would actually have been had the transactions actually occurred on the indicated date, nor do they reflect what may actually occur in the future.

						Pro forma, as adjusted	
	Year ended December 31,			Nine months ended September 30,		Year ended December 31,	Nine months ended September 30,
	2002	2003	2004(1)	2004(1)	2005(2)	2004	2005
				(in thousands)			
Statements of income data:							
Revenue:							
Natural gas and liquids	$	$	$ 72,109	$ 30,048	$ 218,268	$ 331,119	$ 301,362
Transportation and compression	10,660	15,651	18,800	13,344	16,501	40,283	31,630
Interest income and other	7	98	382	282	352	711	496
Total revenues and other income	10,667	15,749	91,291	43,674	235,121	372,113	333,488
Operating expenses:							
Natural gas and liquids			58,707	24,588	184,578	286,828	261,794
Plant operating			2,032	931	7,242	9,105	8,605
Transportation and compression	2,062	2,421	2,260	1,709	2,169	6,694	5,716
General and administrative	1,482	1,661	4,643	2,901	9,128	10,379	11,545
Depreciation and amortization	1,475	1,770	4,471	2,132	8,495	16,803	12,809
Loss (gain) on arbitration settlement, net			(1,457)	2,987	138	(1,457)	138
Interest	250	258	2,301	1,202	8,478	15,496	15,649
Minority interest(3)						492	440
Other expense						555	
Total costs and expenses	5,269	6,110	72,957	36,450	220,228	344,895	316,696
Net income	5,398	9,639	18,334	7,224	14,893	27,218	16,792
Premium on preferred unit redemption			400	400		400	
Net income attributable to partners	$ 5,398	$ 9,639	$ 17,934	$ 6,824	$ 14,893	$ 26,818	$ 16,792
Balance sheet data (at period end):							
Property, plant and equipment, net	$ 23,764	$ 29,628	$ 175,259	$ 172,312	$ 304,704		$ 462,626
Total assets	28,515	49,512	216,785	220,258	484,458		712,880
Total debt, including current portion	6,500		54,452	60,220	183,645		291,234
Total partners capital	19,686	44,245	136,704	129,446	187,028		296,805
Cash flow data:							
Net cash flow provided by (used in):							
Operating activities	$ 8,138	$ 13,702	$ 25,593	$ 17,736	$ 27,119		
Investing activities	(5,231)	(9,154)	(151,797)	(145,728)	(229,892)		
Financing activities	(3,211)	8,671	129,340	141,934	196,594		
Other financial data							
Gross margin(4)	$ 10,660	$ 15,651	$ 32,202	$ 18,804	$ 50,191	$ 84,574	$ 71,198

EBITDA(5)	7,123	11,667	25,106	10,558	31,866	59,517	45,250
Adjusted EBITDA(5)	7,123	11,667	25,806	10,900	34,675	60,217	48,059
Maintenance capital expenditures	$ 170	$ 3,109	$ 1,516	$ 844	$ 1,110		
Growth capital expenditures	5,060	4,526	8,527	3,575	33,409		
Total capital expenditures	$ 5,230	$ 7,635	$ 10,043	$ 4,419	$ 34,519		

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	Year ended December 31,			Nine months ended September 30,		Pro forma, as adjusted: Year ended December 31,	Pro forma, as adjusted: Nine months ended September 30,
	2002	2003	2004(1)	2004(1)	2005(2)	2004	2005
	(in thousands)						
Operating data:							
Appalachia:							
Average throughput volumes (Mcf/d)(6)	50,363	52,472	53,343	52,745	54,804	53,343	54,804
Average transportation rate per Mcf	$ 0.58	$ 0.82	$ 0.96	$ 0.92	$ 1.10	$ 0.96	$ 1.10
Mid-Continent:							
Velma system:							
Gathered gas volume (Mcf/d)(7)			56,441	55,580	69,091	54,315	69,091
Processed gas volume (Mcf/d)(8)			55,202	54,755	64,581	52,391	64,581
Residue gas volume (Mcf/d)(9)			42,659	41,555	52,471	40,702	52,471
NGL production (Bbl/d)(10)			5,799	5,916	6,812	5,711	6,812
Condensate volume (Bbl/d)			185	204	269	191	269
Elk City system:							
Gathered gas volume (Mcf/d)(7)					242,294	239,804	246,539
Processed gas volume (Mcf/d)(8)					116,688	120,505	116,304
Residue gas volume (Mcf/d)(9)					107,182	110,164	106,391
NGL production (Bbl/d)(10)					5,317	5,331	5,347
Condensate volume (Bbl/d)					121	108	136

(1) Includes the acquisition of Spectrum on July 16, 2004, representing five and one-half months operations for the year ended December 31, 2004 and two and one-half months operations for the nine months ended September 30, 2004.
(2) Includes the acquisition of Elk City on April 14, 2005, representing five and one-half months operations for the nine months ended September 30, 2005.
(3) Represents Southwestern s 25% minority interest in NOARK.
(4) We define gross margin as revenue less purchased product costs. Purchased product costs include the cost of natural gas and NGLs we purchase from third parties. Our management views gross margin as an important performance measure of core profitability of our operations and as a key component of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses. The GAAP measure most directly comparable to gross margin is net income. The following table reconciles our net income to gross margin:

	Year ended December 31,			Nine months ended September 30,		Pro forma, as adjusted: Year ended December 31,	Pro forma, as adjusted: Nine months ended September 30,
	2002	2003	2004(1)	2004(1)	2005(2)	2004	2005
	(in thousands)						
Net income	$ 5,398	$ 9,639	$ 18,334	$ 7,224	$ 14,893	$ 27,218	$ 16,792
Plus (minus):							
Interest income and other	(7)	(98)	(382)	(282)	(352)	(711)	(496)
Plant operating			2,032	931	7,242	9,105	8,605
Transportation and compression	2,062	2,421	2,260	1,709	2,169	6,694	5,716
General and administrative	1,482	1,661	4,643	2,901	9,128	10,379	11,545
Depreciation and amortization	1,475	1,770	4,471	2,132	8,495	16,803	12,809
			(1,457)	2,987	138	(1,457)	138

Loss (gain) on arbitration settlement, net							
Interest	250	258	2,301	1,202	8,478	15,496	15,649
Minority interest						492	440
Other expense						555	
Gross margin	$ 10,660	$ 15,651	$ 32,202	$ 18,804	$ 50,191	$ 84,574	$ 71,198

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(5) EBITDA represents net income before net interest expense, income taxes and depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances to members of the managing board and employees of our general partner. EBITDA and adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA may not be the same method used to compute similar measures reported by other companies. The EBITDA calculation below is different from the EBITDA calculation under our credit facility. See Business Credit Facility.

Certain items excluded from EBITDA are significant components in understanding and assessing an entity s financial performance, such as its cost of capital and its tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA and adjusted EBITDA because they provide investors and management with additional information as to our ability to pay our fixed charges and are presented solely as a supplemental financial measure. EBITDA and adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as indicators of our operating performance or liquidity. The table below reconciles adjusted EBITDA to EBITDA and EBITDA to our net income.

						Pro forma, as adjusted	
	Year ended December 31,			Nine months ended September 30,		Year ended December 31,	Nine months ended September 30,
	2002	2003	2004(1)	2004(1)	2005(2)	2004	2005
				(in thousands)			
Net income	$ 5,398	$ 9,639	$ 18,334	$ 7,224	$ 14,893	$ 27,218	$ 16,792
Plus:							
Interest expense	250	258	2,301	1,202	8,478	15,496	15,649
Depreciation and amortization	1,475	1,770	4,471	2,132	8,495	16,803	12,809
EBITDA	7,123	11,667	25,106	10,558	31,866	59,517	45,250
Plus:							
Non-cash compensation expense			700	342	2,809	700	2,809
Adjusted EBITDA	$ 7,123	$ 11,667	$ 25,806	$ 10,900	$ 34,675	$ 60,217	$ 48,059

(6) Based on amount delivered.
(7) Based on lease meter volumes on gathering systems.
(8) Based on amount received at plant inlet.
(9) Based on amount at plant outlet.
(10) Amounts shown are not treated or processed.

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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. You should consider the following risk factors and those described in the section entitled Risk Factors in the accompanying prospectus together with all of the other information included or incorporated by reference in this prospectus supplement and the accompanying prospectus in evaluating an investment in the common units. If any of these risks actually occurs, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline and you may lose some or all of your investment.

Risks Relating to Our Business

We have included under the caption Risk Factors in the accompanying prospectus risks relating to our business in addition to those described below. Please consider each of the risks described in the accompanying prospectus as well as the other risks described below.

We may not generate cash sufficient to pay distributions to our unitholders.

The amounts of cash that we generate may not be sufficient to pay distributions at current or any other level of distributions. 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, we may make cash distributions during periods when we record losses and may not be made during periods when we record profits. The actual amounts of cash we generate will depend upon numerous factors relating to our business which may be beyond our control, some of which are described in the accompanying prospectus under Risk Factors Risks Relating to Our Business Our revenues depend in part on factors beyond our control.

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

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

We acquired Elk City in April 2005 and completed the NOARK acquisition in October 2005 and are currently in the process of integrating their operations with ours. We also have an active, on-going program to identify other potential acquisitions. The integration of previously independent operations with ours can be a complex, costly and time-consuming process. The difficulties of combining Elk City and NOARK, as well as any operations we may acquire in the future, with us include, among other things:

- operating a significantly larger combined company;

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

integrating personnel with diverse business backgrounds and organizational cultures;

consolidating operational and administrative functions;

integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;

the diversion of management s attention from other business concerns;

customer or key employee loss from the acquired businesses;

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- a significant increase in our indebtedness; and

- potential environmental or regulatory liabilities and title problems.

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

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

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

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

We rely exclusively on the revenues generated from our transportation, gathering and processing operations, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of diversification in asset type, a negative development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could impair our results of operations and financial condition.

One of the ways we may grow our business is through the construction of new assets, such as the Sweetwater plant. The construction of additions or modifications to our existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. Any projects we undertake may not be completed on schedule at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a gathering system, the construction may occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which growth does not materialize. Since we are not engaged in the exploration for and development of natural gas reserves, we often do not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, the estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could impair our results of operations and financial condition. In addition, our actual revenues from a project could materially differ from expectations as a result of the price of natural gas, the NGL content of the natural gas processed and other economic factors described in this section.

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

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be reduced.

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

Currently our gathering of natural gas from wells is exempt from regulation under the Natural Gas Act of 1938. However, the implementation of new laws or policies, or interpretations of existing laws, could subject us to regulation by FERC under the Natural Gas Act. We expect that any such regulation would increase our costs, decrease our gross margin and cash flows, or both.

FERC regulation will still affect our business and the market for our products. FERC s policies and practices affect a range of our natural gas pipeline activities, including, for example, its policies on open access transportation, ratemaking, capacity release, and market center promotion, which indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

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

Federal law leaves any economic regulation of natural gas gathering to the states. Texas and Oklahoma have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and, in Texas and Oklahoma, with respect to rate discrimination. Should a complaint be filed or regulation by the Texas Railroad Commission or Oklahoma Corporation Commission become more active, our revenues could decrease.

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

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

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

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complaint or protest against Ozark Gas Transmission s rates could reduce our revenues associated with providing transmission services. We cannot assure you that we will be able to recover all of Ozark Gas Transmission s costs through existing or future rates.

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

FERC s regulatory authority also extends to:

- operating terms and conditions of service;
- the types of services Ozark Gas Transmission may offer to its customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

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

FERC has authority to review pipeline contracts. If FERC determines that a term of any such contract deviates in a material manner from a pipeline s tariff, FERC typically will order the pipeline to remove the term from the contract and execute and refile a new contract with FERC or, alternatively, to amend its tariff to include the deviating term, thereby offering it to all shippers. If FERC audits a pipeline s contracts and finds deviations that appear to be unduly discriminatory, FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should Ozark Gas Transmission fail to comply with all applicable FERC administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1,000,000 per day for each violation.

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

Compliance with pipeline integrity regulations issued by the United States Department of Transportation and state agencies could result in substantial expenditures for testing, repairs and replacement.

United States Department of Transportation and state agency regulations require pipeline operators to develop integrity management programs for transportation pipelines located in high consequence areas. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;

- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

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

Our midstream natural gas operations may incur significant costs and liabilities resulting from a failure to comply with new or existing environmental regulations or a release of hazardous substances into the environment.

The operations of our gathering systems, plant and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of substances into the environment, and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

Risks Inherent in an Investment in Us

You will have very limited voting rights and ability to control management, which may diminish the price at which the common units will trade.

Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its managing board on an annual or other continuing basis. The managing board of our general partner is chosen by the members of our general partner, all of which are subsidiaries of Atlas America.

In addition, our general partner may be removed only upon the vote of the holders of at least 66 $^{2}/3$% of the outstanding common units, excluding common units held by our general partner and its affiliates, and a successor general partner must be elected by a vote of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. Further, if any person or group, other than our general partner or its affiliates, acquires beneficial ownership of 20% or more of any class of units, that person or group will lose voting rights for all of its units. These provisions have the practical effect of making removal of our general partner difficult. Our partnership agreement requires that amendments to our partnership agreement must first be proposed or consented to by our general partner before they can be considered by unitholders. As a result, unitholders will not be able to initiate amendments to our partnership agreement not supported by our general partner. These provisions may diminish the price at which the common units trade.

Our partnership agreement contains provisions that will discourage attempts to change control of us, which may diminish the price at which the common units trade and may prevent a change of control even if doing so would be beneficial to the holders of common units.

Our partnership agreement contains provisions that may discourage a person or group from attempting to remove our general partner or otherwise seeking to change our management. As described in the immediately preceding risk factor, any person or group, other than our general partner or its affiliates, that acquires beneficial ownership of 20% or more of any class of units will lose voting rights for all of its units. In addition, if our general partner is removed under circumstances where cause does not exist and our general partner does not consent to that removal, then:

- the obligations of Atlas America under the omnibus agreement to connect wells to our Appalachian Basin gathering systems and to provide assistance for the expansion of our Appalachian Basin gathering systems will terminate;
- the obligations of Atlas America under the master natural gas gathering agreement will terminate as to any future wells drilled and completed by Atlas America; and
- our general partner will have the right to convert its general partner interest and incentive distribution rights into common units or receive cash in exchange for those interests.

These provisions may diminish the price at which the common units trade. These provisions may also prevent a change of control of us even if a change of control would be beneficial to the holders of the common units.

We may issue additional common units or securities senior to the common units without your approval, which would dilute existing unitholders interests.

Our general partner can cause us to issue additional common units without the approval of unitholders. We may also issue securities senior to the common units without the approval of unitholders. The issuance of additional common units or senior securities may dilute the value of the interests of the existing unitholders in our net assets and dilute the interests of unitholders in distributions by us.

Future sales of our common units may depress the price of our units.

Our general partner owns 1,641,026 of our common units which are not currently registered for public resale. We are required to register the common units for resale upon our general partner s demand if our general partner cannot sell them under Rule 144. We cannot predict the effect, if any, that future sales of our common units or the availability of units for future sales will have on the market price of our common units. Sales of substantial amounts of common units or the perception that such sales could occur could reduce the price that our common units might otherwise obtain.

If Atlas America proceeds with a public offering of securities in an entity that owns our general partner, it may affect the relative attractiveness of an investment in our common units.

Atlas America has recently announced that it is contemplating transferring its ownership interest in our general partner to a new wholly-owned subsidiary and then making a registered, initial public offering of a minority interest in the subsidiary. **This prospectus supplement does not constitute an offer to sell or a solicitation of an offer to buy any such securities for sale.** Any such initial public offering would create an alternative form of investment in our business which some investors may prefer to investing in our common units. The market price of our common units may decline if investors determine that investing in the general partner entity is more attractive than investing in us.

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

Atlas America and its affiliates own and control our general partner, which will also own a 13.2% limited partner interest in us after this offering. We do not have any employees and rely solely on employees of Atlas America and its affiliates who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of Atlas America also own interests in us. Conflicts of interest may arise between Atlas America, our general partner and their affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over our interests and the interests of our unitholders. These conflicts include, among others, the following situations:

- Employees of Atlas America who provide services to us also devote significant time to the businesses of Atlas America in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the employees who provide services to us, which could result in insufficient attention to the management and operation of our business.

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

- Our general partner is allowed to take into account the interests of parties other than us, such as Atlas America, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us.

- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including our agreements with Atlas America.

- Our general partner has limited its liability, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

- Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner securities and reserves, each of which can affect the amount of cash that we distribute to unitholders.

- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

- Our general partner and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses.

- Our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

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

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

We reimburse Atlas America, our general partner and their affiliates, including officers and directors of Atlas America, for all expenses they incur on our behalf. Our general partner has sole discretion to determine the

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amount of these expenses. In addition, Atlas America and its affiliates provide us with services for which we are charged reasonable fees as determined by Atlas America in its sole discretion. The reimbursement of expenses or payment of fees could impair our ability to make distributions.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the completion of this offering, our general partner and its affiliates will own approximately 13.4% of the common units.

You could be liable for any and all of our obligations if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

For a discussion of the expected material federal income tax consequences of owning and disposing of common units, see Tax Considerations in this prospectus supplement.

The IRS could treat us as a corporation, which would substantially reduce the cash available for distribution to unitholders.

The federal income tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. We have, however, received an opinion of Ledgewood, counsel to us and our general partner, that we will be classified as a partnership for federal income tax purposes. Opinions of counsel are based on specific factual assumptions and are not binding on the IRS or any court.

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If we were classified as a corporation for federal income tax purposes, we would pay tax on our income at the corporate tax rate, which is currently 35%. Distributions would generally be taxed again to the unitholders as corporate distributions, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as an entity, the cash available for distribution to you would be substantially reduced, likely causing a substantial reduction in the value of the common units.

We cannot assure you that the law will not be changed and cause us to be treated as a corporation for federal income tax purposes or otherwise to be subject to entity-level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then specified provisions of the partnership agreement will be subject to change, including a decrease in distributions to reflect the impact of that law on us.

We may incur significant legal, accounting and related costs if the IRS challenges the federal income tax positions we take.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus supplement or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain counsel s conclusions or the positions we take. A court may not concur with our conclusions. Any contest with the IRS may materially and negatively impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees and expenses, will be borne directly or indirectly by our unitholders and our general partner.

You may be required to pay taxes on income from us even if you do not receive cash distributions.

You will be required to pay federal income taxes and, in certain cases, state and local income taxes on your allocable share of our income, whether or not you receive cash distributions from us. We cannot assure you that you will receive cash distributions equal to your allocable share of our taxable income or even equal to the tax liability to you resulting from that income. Further, you may incur a tax liability in excess of the amount of cash received upon the sale of your common units or upon our liquidation.

In prior taxable years, unitholders received cash distributions that exceeded the amount of taxable income allocated to the unitholders. This excess was partially the result of depreciation deductions, but was primarily the result of special allocations to our general partner of taxable income earned by our operating subsidiary, which caused a corresponding reduction in the amount of taxable income allocable to us. Our general partner has agreed to receive additional special allocations from our operating subsidiary through the year 2006. We describe these special allocations in Tax Considerations Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions. Since these special allocations increase our general partner s capital account, it will receive an increased distribution upon our liquidation and distributions to unitholders will be correspondingly reduced.

Tax gain or loss on disposition of common units could be different than expected.

Upon the sale of common units, you will recognize gain or loss equal to the difference between the amount realized and your adjusted tax basis in those common units. Prior distributions in excess of the net taxable income you were allocated for a common unit which decreased your tax basis in that common unit will, in effect, become taxable income if you sell the common unit at a price greater than your tax basis in that common unit, even if the price is less than your original cost. A substantial portion of the amount realized, whether or not representing gains, may be ordinary income. Furthermore, should the IRS successfully contest our conventions, including our method of allocating income and loss as between transferors and transferees, you could realize more gain on the sale of common units than would be the case under those conventions without the benefit of decreased income in prior years.

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Investors, other than individuals who are U.S. residents, may have adverse tax consequences from owning units.

Investment in common units by tax-exempt entities, regulated investment companies and foreign persons raises issues unique to them. For example, virtually all of our income will be unrelated business taxable income and will be taxable to organizations exempt from federal income tax, including IRAs and other retirement plans. Distributions to foreign persons will be reduced by withholding taxes.

We treat a purchaser of common units as having the same tax benefits without regard to the actual common units purchased; the IRS may challenge this treatment which could reduce the value of the units.

Because we cannot match transferors and transferees of common units, we will take certain tax positions that may not conform with all aspects of proposed and final Treasury regulations. For example, upon a transfer of units, we treat a portion of the Section 743(b) adjustment to a common unitholder s tax basis in our assets as amortizable over the same remaining life and by the same method as the underlying assets, or nonamortizable if the underlying assets are nonamortizable. A successful IRS challenge to those conventions, including our method of amortizing Section 743(b) adjustments, could reduce the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax returns.

You will likely be subject to state and local taxes as a result of an investment in common units.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property. Further, you may be subject to penalties for failure to comply with those requirements. We currently own assets and do business in Ohio, Oklahoma, Pennsylvania, Texas and New York. Each of these states, except Texas, currently imposes a personal income tax. It is your responsibility to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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USE OF PROCEEDS

We will receive net proceeds of approximately $110.0 million from the sale of the common units we are offering and our general partner s related capital contribution, after deducting the underwriting discounts and estimated offering expenses payable by us. We expect to receive net proceeds of approximately $126.6 million if the underwriters option to acquire additional common units is exercised in full.

We intend to use all of the net proceeds from this offering, including the net proceeds from the exercise of the underwriters option to acquire additional common units, if any, and our general partner s related capital contribution, to repay a portion of the indebtedness and accrued interest outstanding under our revolving credit facility. Affiliates of Citigroup Global Markets Inc., Wachovia Capital Markets, LLC and KeyBanc Capital Markets, underwriters participating in this offering, are lenders under the credit facility. See Underwriting Relationships. We used the proceeds of credit facility borrowings principally for our acquisitions. As of November 21, 2005, this credit facility had outstanding borrowings of $361.5 million at a weighted average interest rate of 6.8% and matures in April 2010.

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2005 on an actual basis and on a pro forma basis to give effect to the NOARK acquisition, borrowings under our credit facility and redemption of the NOARK 7.15% notes severally guaranteed by Atlas Arkansas, and on a pro forma as adjusted basis to give effect to the sale of common units in this offering and the application of the net proceeds as described in Use of Proceeds.

You should read the following table in conjunction with our historical consolidated financial statements and related notes, Management s Discussion and Analysis of Financial Condition and Results of Operations and other financial information included elsewhere or incorporated by reference in this prospectus supplement.

	As of September 30, 2005		
	Actual	Pro forma	Pro forma, as adjusted
		(in thousands)	
Cash and cash equivalents	$ 12,035	$ 26,780	$ 26,780
Debt:			
Credit facility	$ 183,500	$ 361,500	$ 251,489
NOARK 7.15% non-recourse notes(1)		39,600	39,600
Other	145	145	145
Total debt	183,645	401,245	291,234
Partners capital:			
Common unitholders	227,065	226,836	334,533
General partner	6,407	6,402	8,716
Accumulated other comprehensive loss	(46,444)	(46,444)	(46,444)
Total partners capital	187,028	186,794	296,805
Total capitalization	$ 370,673	$ 588,039	$ 588,039

(1) These notes are guaranteed by Southwestern.

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

As of November 18, 2005, we had 9,519,266 common units outstanding held by 89 holders of record, including common units held in street name. As of May 14, 2004, our common units began trading on the New York Stock Exchange under the symbol APL. Before that, our common units were traded on the American Stock Exchange under the symbol APL. In connection with our initial public offering in January 2000, we also issued 1,641,026 subordinated units to our general partner, all of which converted into common units on January 1, 2005.

The following table sets forth the range of high and low sales prices of our common units and cash distributions on our common units for the periods indicated. The last reported sale price of our common units on the New York Stock Exchange on November 21, 2005 was $42.00 per unit.

	High	Low	Distributions declared(1)
Fiscal 2005			
Fourth quarter (through November 18, 2005)	$ 49.21	$ 42.00	$ (2)
Third quarter	49.72	43.75	0.810
Second quarter	46.39	41.25	0.770
First quarter	49.00	40.00	0.750
Fiscal 2004			
Fourth quarter	42.90	37.67	0.720
Third quarter	38.32	33.46	0.690
Second quarter	40.03	32.60	0.630
First quarter	41.50	34.00	0.630
Fiscal 2003			
Fourth quarter	42.50	34.70	0.625
Third quarter	36.00	29.40	0.620
Second quarter	31.70	24.16	0.580
First quarter	28.96	24.90	0.560
Fiscal 2002			
Fourth quarter	27.90	21.80	0.540
Third quarter	26.95	20.40	0.540
Second quarter	29.10	22.00	0.540
First quarter	29.60	23.51	0.520

(1) Distributions are shown in the quarter with respect to which they were declared.
(2) Distribution not yet declared.

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PRO FORMA FINANCIAL DATA

The following unaudited pro forma financial data reflects our historical results as adjusted on a pro forma basis to give effect to our April 2004, July 2004 and June 2005 offerings of common units, the completion of the Spectrum, Elk City and NOARK acquisitions and this offering. The acquisition and offering adjustments are described in the notes to the unaudited pro forma financial data. The unaudited pro forma financial data and accompanying notes should be read together with our Management s Discussion and Analysis of Financial Condition and Results of Operation, our historical financial statements and related notes and the historical financial statements and related notes of Elk City and its predecessor and Enogex Arkansas Pipeline included or incorporated by reference in this prospectus supplement.

We accounted for the NOARK acquisition and the acquisitions of Spectrum and Elk City in the unaudited pro forma financial data using the purchase method in accordance with the guidance of Statement of Financial Accounting Standards No. 141, Business Combinations. For purposes of developing the unaudited pro forma financial information, we have allocated the purchase prices to Spectrum s, Elk City s, and NOARK s gas gathering, processing and/or transmission facilities based on their fair market value.

The unaudited pro forma balance sheet information reflects the following transactions as if they occurred as of September 30, 2005:

- the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs;

- the increase in our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition; and

- this offering and the application of the net proceeds as described under Use of Proceeds.

The unaudited pro forma statement of income information for the year ended December 31, 2004 reflects the following transactions as if they occurred as of January 1, 2004:

- the Spectrum acquisition, which occurred in July 2004, for total consideration of $141.6 million, including the payment of income taxes due as a result of the transaction and other related transaction costs;

- the Elk City acquisition, which occurred in April 2005, for total consideration of $196.0 million, including related transaction costs;

- the closing of our $270.0 million credit facility, which occurred in April 2005, and borrowings under it to finance the Elk City acquisition and repay amounts outstanding under our previous credit facility;

- the increase of our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition;

our public offering of 2,100,000 common units, which was completed in July 2004 at a public offering price of $34.76 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were used principally to repay indebtedness incurred in connection with the Spectrum acquisition;

our public offering of 2,300,000 common units, which was completed in June 2005 at a public offering price of $41.95 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were used principally to repay indebtedness incurred in connection with the Elk City acquisition;

the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs, and the redemption of the portion of the NOARK 7.15% notes severally guaranteed by Atlas Arkansas; and

this offering and the application of the net proceeds as described under Use of Proceeds.

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The unaudited pro forma statement of income information for the nine months ended September 30, 2005 reflects the following transactions as if they occurred as of January 1, 2005:

the Elk City acquisition, which occurred in April 2005, for total consideration of $196.0 million, including related transaction costs;

the closing of our $270.0 million credit facility, which occurred in April 2005, and borrowings under it to finance the Elk City acquisition and repay amounts outstanding under our previous credit facility;

the increase of our credit facility to $400.0 million, which occurred on October 31, 2005, and borrowings under it to finance the NOARK acquisition;

our public offering of 2,300,000 common units, which was completed in June 2005, at a public offering price of $41.95 per common unit, and a capital contribution by our general partner to maintain its 2% general partner interest, the net proceeds of which were principally used to repay indebtedness incurred in connection with the Elk City acquisition;

the NOARK acquisition, which occurred on October 31, 2005, for consideration of $163.0 million, plus $10.2 million for working capital adjustments and $2.3 million of estimated transaction costs, and the redemption of the portion of the NOARK 7.15% notes severally guaranteed by Atlas Arkansas; and

this offering and the application of the net proceeds as described under Use of Proceeds.

Elk City s historical fiscal year ended August 31, 2004 is not within 93 days of our fiscal year end. Accordingly, for pro forma purposes, statement of income information for the year ended December 31, 2004 is based on Elk City s historical financial results for the twelve months ended November 30, 2004 and was created by subtracting the quarter ended November 30, 2003 from Elk City s income statement for the year ended August 31, 2004 and adding the quarter ended November 30, 2004. For our pro forma statement of income information for the nine months ended September 30, 2005, we included Elk City s income statement for the three months ended February 28, 2005. Elk City was included within our historical results for the nine months ended September 30, 2005 from its date of acquisition on April 14, 2005.

The unaudited pro forma balance sheet and the pro forma statements of income were derived by adjusting our historical financial statements. However, our management believes that the adjustments provide a reasonable basis for presenting the significant effects of the transactions described above. The unaudited pro forma financial data presented are for informational purposes only and are based upon available information and assumptions that we believe are reasonable under the circumstances. You should not construe the unaudited pro forma financial data as indicative of the combined financial position or results of operations that we, Spectrum, Elk City and NOARK would have achieved had the transactions been consummated on the dates assumed. Moreover, they do not purport to represent our, Spectrum s, Elk City s or NOARK s combined financial position or results of operations for any future date or period.

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ATLAS PIPELINE PARTNERS, L.P.

PRO FORMA CONSOLIDATED BALANCE SHEET (UNAUDITED)

SEPTEMBER 30, 2005

(in thousands)

	Historical Atlas Pipeline	Historical EAPC	Acquisition adjustments	Pro forma	Offering adjustments	Pro forma, as adjusted
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 12,035	$ 14,502	$ 178,000(1)	$ 26,780	$ 107,697(5)	$ 26,780
			(177,757)(1)		2,314(6)	
					(110,011)(5)(6)	
Accounts receivable affiliates	4,418	7,236	(5,145)(2)	6,509		6,509
Accounts receivable	41,289	785	5,145(2)	47,219		47,219
Current portion of hedge asset	14,993			14,993		14,993
Prepaid expenses and other current assets	1,595	324		1,919		1,919
Total current assets	74,330	22,847	243	97,420		97,420
PROPERTY, PLANT AND EQUIPMENT	324,517	146,509	32,006(4)	503,032		503,032
Less accumulated depreciation	(19,813)	(20,593)		(40,406)		(40,406)
Net property, plant and equipment	304,704	125,916	32,006	462,626		462,626
MINORITY INTEREST IN NOARK ASSETS		3,359	40,544(4)	43,903		43,903
LONG-TERM HEDGE ASSET	5,970			5,970		5,970
INTANGIBLES, NET	12,398			12,398		12,398
GOODWILL	80,201			80,201		80,201
OTHER ASSETS	6,855	1,532	(425)(3)	10,362		10,362
			2,400(1)			
	$ 484,458	$ 153,654	$ 74,768	$ 712,880	$	$ 712,880
LIABILITIES AND PARTNERS CAPITAL						
CURRENT LIABILITIES:						
Current portion of non-recourse long-term debt	$	$ 1,200	$	$ 1,200	$	$ 1,200
Current portion of other long-term debt	63	800	(800)(4)	63		63
Accrued liabilities	6,360	3,037		9,397		9,397
Current portion of hedge liability	37,663			37,663		37,663
Accrued producer liabilities	32,543			32,543		32,543
Accounts payable	7,257	6,468	1,551(2)	15,276		15,276
Accounts payable affiliates		1,551	(1,551)(2)			
Total current liabilities	83,886	13,056	(800)	96,142		96,142
LONG-TERM HEDGE LIABILITY	29,962			29,962		29,962
NON-RECOURSE LONG-TERM DEBT		38,400		38,400		38,400
OTHER LONG-TERM DEBT	183,582	25,600	178,000(1)	361,582	(110,011)(5)(6)	251,571
			(25,600)(4)			
DEFERRED INCOME TAXES		21,893	(21,893)(4)			
PARTNERS CAPITAL:						
Limited partners interests	227,065			226,836	107,697(5)	334,533
			(229)(1)			
General partner s interest	6,407		(5)(1)	6,402	2,314(6)	8,716
Stockholders equity		54,705	(54,705)(4)			

Accumulated other comprehensive loss	(46,444)			(46,444)		(46,444)
Total partners capital	187,028	54,705	(54,939)	186,794	110,011	296,805
	$ 484,458	$ 153,654	$ 74,768	$ 712,880	$	$ 712,880

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ATLAS PIPELINE PARTNERS, L.P.

PRO FORMA CONSOLIDATED STATEMENT OF INCOME (UNAUDITED)

FOR THE YEAR ENDED DECEMBER 31, 2004

(in thousands, except per unit data)

	Historical Atlas Pipeline	Historical Spectrum	Historical Elk City	Historical EAPC	Acquisition adjustments	Pro forma	Offering adjustments	Pro forma, as adjusted
REVENUES:								
Natural gas and liquids third party	$ 72,109	$ 67,643	$ 11,376	$ 253	$ 166,544(7)	$ 317,925	$	$ 317,925
Natural gas and liquids affiliates			123,975	55,763	(166,544)(7)	13,194		13,194
Transportation third party	76			10,364	4,143(7)	14,583		14,583
Transportation affiliates	18,724			11,119	(4,143)(7)	25,700		25,700
Interest and other	382			329		711		711
	91,291	67,643	135,351	77,828		372,113		372,113
COSTS AND EXPENSES:								
Cost of gas sold	58,707	54,565	118,537	55,019		286,828		286,828
Operating expenses	2,032	2,474	4,599			9,105		9,105
Transportation	2,260			4,434		6,694		6,694
General and administrative	4,643	7,509	2,482	3,756	840(8)	10,379		10,379
					(2,482)(8)			
					(6,369)(9)			
Gain on arbitration settlement, net	(1,457)					(1,457)		(1,457)
Depreciation and amortization	4,471	1,638	2,153	3,249	(7,040)(10)	16,803		16,803
					12,332(10)			
Minority interest in NOARK				492		492		492
	70,656	66,186	127,771	66,950	(2,719)	328,844		328,844
OPERATING INCOME	20,635	1,457	7,580	10,878	2,719	43,269		43,269
OTHER (INCOME) EXPENSE:								
Interest expense	2,301	1,712		5,287	11,345(11)(13)	20,645	(5,149)(12)	15,496
Other (income) expense		(88,551)	(3)		89,109(9)	555		555
	2,301	(86,839)	(3)	5,287	100,454	21,200	(5,149)	16,051
Income (loss) before income taxes	18,334	88,296	7,583	5,591	(97,735)	22,069	5,149	27,218
Provision for income taxes		(32,319)		(2,162)	34,481(14)			
Net income (loss)	18,334	55,977	7,583	3,429	(63,254)	22,069	5,149	27,218
Premium on preferred unit redemption	(400)					(400)		(400)
	$ 17,934	$ 55,977	$ 7,583	$ 3,429	$ (63,254)	$ 21,669	$ 5,149	$ 26,818

Net income attributable to partners			
Net income limited partners	$ 14,864	$ 18,524(15)	$ 23,569(15)
Net income general partner	3,070	3,145(15)	3,248(15)
Net income attributable to partners	$ 17,934	$ 21,669	$ 26,818
Basic and diluted net income per limited partner unit	$ 2.53	$ 1.95	$ 1.93
Weighted average units outstanding:			
Basic	5,866	9,505	12,205
Diluted	5,870	9,509	12,209

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ATLAS PIPELINE PARTNERS, L.P.

PRO FORMA CONSOLIDATED STATEMENT OF INCOME (UNAUDITED)

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2005

(in thousands, except per unit data)

	Historical Atlas Pipeline	Historical Elk City	Historical EAPC	Acquisition adjustments	Pro forma	Offering adjustments	Pro forma, as adjusted
REVENUES:							
Natural gas and liquids third party	$ 218,268	$ 3,497	$ 237	$ 69,658(7)	$ 291,660	$	$ 291,660
Natural gas and liquids affiliates		37,235	42,125	(69,658)(7)	9,702		9,702
Transportation third party	54		8,174	1,999(7)	10,227		10,227
Transportation affiliates	16,447		6,955	(1,999)(7)	21,403		21,403
Interest and other	352		144		496		496
	235,121	40,732	57,635		333,488		333,488
COSTS AND EXPENSES:							
Cost of gas sold	184,578	36,665	40,551		261,794		261,794
Operating expenses	7,242	1,363			8,605		8,605
Transportation	2,169		3,547		5,716		5,716
General and administrative	9,128	850	2,207	(850)(8)	11,545		11,545
				210(8)			
Gain on arbitration settlement, net	138				138		138
Depreciation and amortization	8,495	628	2,475	(3,103)(10)	12,809		12,809
				4,314(10)			
Minority interest in NOARK			440		440		440
	211,750	39,506	49,220	571	301,047		301,047
OPERATING INCOME	23,371	1,226	8,415	(571)	32,441		32,441
OTHER (INCOME) EXPENSE:							
Interest expense	8,478		3,654	8,666(11)(13)	20,798	(5,149)(12)	15,649
	8,478		3,654	8,666	20,798	(5,149)	15,649
Income (loss) before income taxes	14,893	1,226	4,761	(9,237)	11,643	5,149	16,792
Provision for income taxes			(1,887)	1,887(14)			
Net income (loss)	$ 14,893	$ 1,226	$ 2,874	$ (7,350)	$ 11,643	$ 5,149	$ 16,792

Net income limited partners	$ 9,003	$ 5,819(15)	$ 10,864(15)
Net income general partner	5,890	5,824(15)	5,928(15)
Net income (loss)	$ 14,893	$ 11,643	$ 16,792
Basic net income per limited partner unit	$ 1.09	$ 0.61	$ 0.89
Diluted net income per limited partner unit	$ 1.09	$ 0.61	$ 0.89
Weighted average units outstanding:			
Basic	8,226	9,507	12,207
Diluted	8,277	9,558	12,258

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ATLAS PIPELINE PARTNERS, L.P.

NOTES TO UNAUDITED PRO FORMA FINANCIAL STATEMENTS

1. To reflect the application of $178,000,000 of borrowings under our credit facility for (a) payment to sellers and various acquisition costs of $175,123,000, which are allocated to the underlying assets and liabilities acquired as described in note 4, (b) loan costs of $2,400,000, which will be amortized over the remaining term of the credit facility, (c) interest of $234,000, all of which relates to post-September 30, 2005 periods and charged herein to partners capital, and (d) $243,000 to us. We describe our amended credit facility under Business Credit Facility.
2. To reclassify affiliated receivables to third-party receivables.
3. To remove $425,000 from our other assets for acquisition costs previously paid or accrued and to include that amount within the purchase price allocation described in note 4 below.
4. To reflect the allocation of the total purchase price for NOARK and various acquisition costs of $175,548,000 to the assets and liabilities acquired, consisting of $175,123,000 payment to seller and various acquisition costs as described in note 1 and the $425,000 of acquisition costs previously paid or accrued as described in note 3. The deferred tax liability and affiliated accounts payable were not assumed by us and remain the responsibility of the seller. Also reflects the repayment of $26,400,000 of the 7.15% NOARK notes by the seller from the net proceeds from its sale of NOARK. This amount was deposited into an escrow account for the purpose of repayment and retirement of this portion of the notes. The remaining outstanding portion of the NOARK notes is guaranteed by Southwestern, the 25% minority interest owner in NOARK, and is non-recourse to us. An acquisition adjustment has been included to adjust minority interest to reflect Southwestern s interest in the non-recourse NOARK notes.
5. To reflect net proceeds from this offering of $107,697,000 after offering costs of $5,703,000, assuming 2,700,000 common units at a price of $42.00 per unit, used to repay borrowings under the credit facility.
6. To reflect our general partner s 2% capital contribution associated with this offering in accordance with the terms of the partnership agreement, used to repay borrowings under the credit facility.
7. To reclassify affiliated revenues to third-party revenues.
8. To reflect the elimination of the overhead allocated to Elk City by its parent and its replacement with an overhead allocation to be made by our general partner in accordance with a new allocation agreement.
9. To reflect the elimination of non-cash compensation costs of $6,369,000 related to the vesting of stock options upon change of control and the gain of $89,109,000, in each case, on the sale of Spectrum s assets to us.
10. To reflect the adjustment to depreciation expense for Spectrum for six and one half months and for Elk City and NOARK for 12 months based upon the cost of the acquired gas gathering and transmission facilities using depreciable lives ranging from 3 to 40 years and using the straight-line method.
11. To reflect the adjustments to interest expense resulting from borrowings under the credit facility to (a) finance the acquisitions of Spectrum, Elk City, and NOARK, (b) reflect the net proceeds of the April 2004, July 2004, and June 2005 offerings of common units, and (c) reflect the repayment of a portion of the NOARK notes.
12. To reflect the adjustment to interest expense resulting from the repayment of amounts outstanding under the credit facility with proceeds from this offering.
13. To reflect the amortization of deferred financing costs related to our new credit facility to finance the Elk City acquisition and the amendment to the credit facility to finance the NOARK acquisition.
14. To reflect the elimination of federal and state income taxes following the conversion of Spectrum and NOARK, which were both C-corporations, to limited liability companies concurrent with their acquisition by us.
15. It is impracticable to determine what cash available for distribution would have been on a pro forma basis. Accordingly, the allocation of net income between the general partner and the limited partners reflects historical incentive distributions.

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BUSINESS

General

We are a publicly-traded midstream energy services provider engaged in the transmission, gathering and processing of natural gas. We conduct our business through two operating segments: our Mid-Continent operations and our Appalachian operations.

We own and operate through our Mid-Continent operations:

- a 75% interest in a FERC-regulated, 565-mile interstate pipeline system, that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 322 MMcf/d;
- two natural gas processing plants with aggregate capacity of approximately 230 MMcf/d and one treating facility with a capacity of approximately 200 MMcf/d, both located in Oklahoma; and
- 1,765 miles of active natural gas gathering systems located in Oklahoma, Arkansas, northern Texas and the Texas panhandle, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or Ozark Gas Transmission.

We own and operate through our Appalachian operations 1,500 miles of active natural gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Through an omnibus agreement and other agreements between us and Atlas America, the parent of our general partner and a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin, we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas America. Among other things, the omnibus agreement requires Atlas America to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport. These agreements are continuing obligations and have no specified term except that they will terminate if our general partner is removed without cause.

Since our initial public offering in January 2000, we have completed five acquisitions at an aggregate cost of approximately $516.7 million, including, most recently, our October 2005 acquisition of Atlas Arkansas, which owns a 75% interest in NOARK, and our April 2005 acquisition of Elk City.

Both our Mid-Continent and Appalachian operations are located in areas of abundant and long-lived natural gas production and significant new drilling activity. The Ozark Gas Transmission system and our gathering systems are connected to approximately 6,250 central delivery points or wells, giving us significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. We provide fee-based, FERC-regulated transmission services through Ozark Gas Transmission under both long-term and short-term contractual arrangements. We intend to increase the portion of the transmission services provided under long-term contracts. As a result of the location and capacity of the Ozark Gas Transmission system and our gathering and processing assets, we believe we are strategically positioned to capitalize on the significant increase in drilling activity in our service areas and the basis spread across Ozark Gas Transmission. We intend to continue to expand our business through strategic acquisitions and organic growth projects, including our recently announced plan to construct the Sweetwater gas plant, that increase distributable cash flow per unit.

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The following table shows the pro forma gross margin for our operating units for the periods indicated:

	Pro forma			
	Year ended December 31, 2004		Nine months ended September 30, 2005	
	$	%	$	%
Mid-Continent:				
Velma and Elk City	$ 43,294	51.2%	$ 37,757	53.0%
NOARK	22,480	26.6%	16,940	23.8%
	65,774	77.8%	54,697	76.8%
Appalachia	18,800	22.2%	16,501	23.2%
	$ 84,574	100.0%	$ 71,198	100.0%

Please see Summary Historical Consolidated and Other Financial Data for a definition of gross margin and a reconciliation of pro forma gross margin to our pro forma net income.

Recent Acquisitions

Acquisition of Atlas Arkansas and Controlling Interest in NOARK. On October 31, 2005, we acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), all of the outstanding equity of Atlas Arkansas, which owns a 75% interest in NOARK, for $165.3 million, including estimated related transaction costs, plus $10.2 million for working capital adjustments. The remaining 25% interest in NOARK is owned by Southwestern, a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Before the closing of our acquisition, Atlas Arkansas converted from an Oklahoma corporation into an Oklahoma limited liability company and changed its name from Enogex Arkansas Pipeline Company. The NOARK acquisition further expands our activities in the Mid-Continent region and provides an additional source of fee-based cash flows from a FERC-regulated interstate pipeline system and an intrastate gas gathering system. NOARK s geographic position relative to our other businesses and interconnections with major interstate pipelines also provides us with organic growth opportunities. NOARK s principal assets include:

The Ozark Gas Transmission system, a 565-mile FERC-regulated interstate pipeline system which extends from southeast Oklahoma through Arkansas and into southeast Missouri and has a throughout capacity of approximately 322 MMcf/d. The system includes approximately 30 supply and delivery interconnections and two compressor stations.

The Ozark Gas Gathering system, a 365-mile intrastate natural gas gathering system, located in eastern Oklahoma and western Arkansas, and 11 associated compressor stations.

We financed the acquisition by borrowing under our senior secured credit facility. We intend to use all of the net proceeds from this offering to repay a portion of the balance outstanding under our credit facility. We expect the NOARK acquisition to be immediately accretive to our distributable cash flow per unit.

Ozark Gas Transmission transports natural gas from receipt points in eastern Oklahoma and western Arkansas, where the Arkoma Basin is located, to interstate pipelines in northeastern and central Arkansas and to local distribution companies in Arkansas and Missouri. Ozark Gas Gathering provides access to natural gas supplies that are then transported through Ozark Gas Transmission. Ozark Gas Transmission s revenues are comprised of FERC-regulated transmission fees that are based on firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates. The Ozark transmission and gathering systems transported an average of 163.9 MMcf/d during the nine months ended September 30, 2005, and 207.2 MMcf/d during October 2005.

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Our gas supply strategy in the Mid-Continent region is to establish long-term, value-oriented relationships with our producing customers. We have long-standing relationships with many of our Mid-Continent customers which account for a substantial majority of our gathering and processing throughput. The Mid-Continent region, one of the most prolific natural gas-producing regions in North America, has recently experienced a significant increase in oil and gas drilling activity driven by long-term projections of continued growth in U.S. natural gas demand and the application of new drilling and production technologies. For example, the average monthly drilling rig count in Oklahoma during 2005 through October was 153, a 19% increase over the average monthly drilling rig count in 2003 of 129. Ozark Gas Gathering accesses the Fayetteville Shale Play, located in the Arkoma Basin. Southwestern Energy Company, an active driller in the area, has announced that it expects to drill between 175 to 200 wells in the Fayetteville Shale Play in 2006. Southwestern Energy Company also recently announced the purchase of ten drilling rigs which are expected to be delivered monthly beginning in November 2005 for use in the Play. In developing its Fayetteville Shale acreage, Southwestern Energy Company announced on October 27, 2005, that it has drilled 67 wells to date in ten different areas. Southwestern Energy Company has announced that it expects to further evaluate its Fayetteville Shale acreage over the next 12-15 months by drilling an additional 35 to 40 wells.

As part of the acquisition, Enogex agreed to redeem the 40% portion of NOARK s 7.15% notes due 2018 for which it is severally liable as guarantor as promptly as practicable after the closing. At the closing, Enogex deposited $32.2 million with UMB Bank, N.A., as escrow agent, in order to fulfill this redemption obligation. Enogex must deposit additional amounts into the escrow account in the event the amount deposited on the closing date is insufficient for payment of the redemption price in full; the redemption price will be calculated shortly before the redemption and the redemption will occur on December 5, 2005. Southwestern, the other partner in NOARK, will remain liable for the remaining 60% portion of the 7.15% notes. Under the NOARK partnership agreement, payments on the notes will be made from amounts otherwise distributable to Southwestern and, if that amount is insufficient, Southwestern is required to make a capital contribution to NOARK.

Acquisition of Elk City. In April 2005, we acquired all of the outstanding equity interests in Elk City for $196.0 million, including transaction costs. Elk City s principal assets include approximately 300 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, a natural gas processing facility in Elk City, Oklahoma, with a total capacity of approximately 130 MMcf/d, and a gas treating facility in Prentiss, Oklahoma, with a total capacity of approximately 200 MMcf/d. Gathered volumes averaged 242.3 MMcf/d for the nine months ended September 30, 2005. The system connects to over 300 receipt points. The acquisition expanded the scale of our Mid-Continent operations and built upon our experience in processing and gathering.

Contracts and Customer Relationships

In our Mid-Continent operations, we either purchase gas from producers, or intermediaries, into receipt points on our systems and then sell the gas, and produced NGLs, if any, off of delivery points on our systems, or we transport gas across our systems, from receipt to delivery point, without taking title to the gas. Beyond the distinction of purchasing or transporting gas, we have a variety of contractual relationships with our producers and shippers, including fixed-fee, percentage-of-proceeds and keep-whole. Ozark Gas Transmission s revenues are comprised of FERC-regulated transmission fees that are based on firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates. Under the fixed fee contracts, we provide gathering, compression, treating and dehydration services to our customers for a flat fee. Gross margin from fee-based services depends solely on throughput volume and is not affected by changes in commodity prices. Under the percentage-of-proceeds contracts, we purchase natural gas at the wellhead, process the natural gas and sell the plant residue gas and NGLs at market-based prices, remitting to producers a percentage of the proceeds. Under keep-whole contracts, we gather natural gas from the producer, process the natural gas and sell the resulting NGLs at market price. The extraction of the NGLs lowers the Btu content of the natural gas. Therefore, under keep-whole contracts, we must replace these Btus by either

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purchasing natural gas at market prices or making a cash payment to the producer and our profitability is dependent upon the spread between the price of natural gas, our feedstock, and NGLs, our manufactured product. The gross margin associated with each of these contractual arrangements can vary from period to period due to a variety of factors, including changing prices of natural gas and NGLs, producers optionality between contract types (e.g., percentage-of-proceeds and keep-whole), and producers optionality between transporting and selling gas.

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

Business Strategy

Our primary objectives are to increase distributable cash flow per unit and returns to our unitholders while maintaining a strong credit profile and financial flexibility by executing the following strategies:

Maximize cash flows from our existing businesses through efficient marketing of our services and facilities and control of our operating costs. We intend to continue to control our operating costs by efficiently managing our existing and acquired businesses and achieving economies of scale. We have additional capacity in our gathering systems and have, or can upgrade at minimal cost, the capacity at our processing and treating facilities. As a result we can readily increase the amount of natural gas we transport and process.

Continuing to increase the amount of our operating cash flow generated by long-term, fee-based contracts. We intend to continue to secure long-term, fee-based contracts both in our existing operations and through strategic acquisitions in order to further diversify our contract mix.

Expanding existing businesses through organic growth opportunities. We continually evaluate opportunities to expand our operations through the construction of pipeline extensions to connect additional wells and access additional reserves. In addition, we plan to complete the Sweetwater plant, a 120 MMcf/d natural gas processing plant near our Prentiss treatment plant, by mid-2006. We believe that our agreements with Atlas America present a favorable source of organic growth and that our competitive position and customer relationships in the Mid-Continent region will continue to yield additional expansion opportunities.

Expand operations through strategic acquisitions. Our recent acquisitions have provided geographic diversification and expanded the midstream services we provide. We intend to continue to make accretive acquisitions of midstream energy assets such as natural gas gathering systems and natural gas and NGL transmission, processing and storage facilities. We will seek strategic opportunities in our current areas of operation, as well as other regions of the United States with significant natural gas and oil reserves or with growing demand for natural gas and oil. We believe that there will continue to be attractive acquisition opportunities in the midstream sector of the energy industry.

Maintain a flexible capital structure based on a strong balance sheet by financing our growth through a balanced combination of debt and equity. To provide financial flexibility to fund future acquisition and expansion opportunities, we will continue to opportunistically access the capital markets. We intend to maintain a strong balance sheet by financing growth with a combination of long-term debt and equity. Including our initial public offering in 2000, we have accessed the equity markets five times, raising approximately $243.3 million in gross proceeds. Upon the completion of this offering, we also expect to have unused capacity under our revolving credit facility to finance system expansions, acquisitions and working capital needs. Historically, because of our financial flexibility, we have been able to take advantage of opportunities for expansion and optimization as they arise.

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Competitive Strengths

Strategically positioned for organic growth. We are a leading provider of transportation and natural gas gathering services in the Anadarko Basin and the Arkoma Basin, and the Golden Trend area of Oklahoma and the Appalachian Basin and of natural gas processing services in Oklahoma. These regions are characterized by long-lived wells and substantial developed and undeveloped natural gas reserves which we believe will continue to promote significant drilling activity. We provide our gathering and processing services to over 6,250 wells and central delivery points. We expect the breadth of our operations in our service areas, our customer focus and our relationship with Atlas America will allow us to continue to connect new wells and capture new natural gas volumes quickly and cost-effectively. Additionally, the NOARK acquisition increases our size and presence in the Mid-Continent region, including expanding our operations east into the Arkoma Basin.

Diversified asset base. Our operations are divided between the active Mid-Continent Basin, including Arkansas, Oklahoma, southern Missouri, northern Texas and the Texas panhandle, where we transport, gather, process and treat third-party gas volumes, and the Appalachian Basin, where we access new volumes through long-term gathering agreements with Atlas America. In addition, our revenues are generated under a variety of contract structures, including FERC-regulated transmission fees from Ozark Gas Transmission, fixed fees from our gathering and treating businesses, percentage-of-proceeds contracts from our gathering and processing businesses and, to a lesser extent, keep-whole contracts from our Elk City processing plant, which we may bypass during periods of unfavorable processing margins.

Stability from long-term contracts and strong customer relations. Our gas supply strategy in the Mid-Continent region is to establish long-term, value-oriented relationships with our producing customers. We have long-standing relationships with many of our Mid-Continent customers which account for a substantial majority of our gathering and processing throughput. Ozark Gas Transmission also has strong relationships with numerous shippers that contract for transmission services either on a short or long-term firm basis or interruptible basis. In addition, our Appalachian operations generate substantially all of their volumes under a long-term omnibus agreement with Atlas America whereby Atlas America is required to commit to our gathering system all wells it drills and operates that are within 2,500 feet of the system. Wells under this agreement are committed for the life of their respective leases, typically over 30 years.

Relationship with Atlas America. The agreements between us and Atlas America are intended to maximize the use and expansion of our Appalachian Basin gathering systems and the amount of natural gas they transport. Atlas America has a significant presence within its core Appalachian Basin areas of New York, Ohio and Pennsylvania as well as an active drilling and development program, which we believe will continue to provide us a secure and stable source of natural gas supply. Since our inception in January 2000 through September 30, 2005, we have connected 1,508 Atlas America wells to our system and 411 Atlas America wells for the twelve months ended September 30, 2005.

Efficient assets which offer low maintenance capital expenditure requirements, system flexibility and superior customer service. Our transportation and gathering systems and processing plants carry low capital expenditure needs, and we have made capital expenditures to improve the efficiency and competitiveness of our facilities:

- A substantial portion of our compressors are electric-powered rather than the higher-cost natural gas-powered compressors used by many of our competitors which results in higher revenues from higher efficiency and lower fuel costs.

- We believe that we are one of only two processors in our Velma area of operations that can process natural gas with high hydrogen sulfide and carbon dioxide content.

- We provide our customers with superior NGL recovery rates.

Our gathering systems provide our customers increased flexibility:

- Our Velma gathering system provides low pressure service, enabling our customers to produce their wells at higher rates and extend the economic lives of their wells.
- Our Elk City and Appalachia gathering systems provide our customers with superior access to natural gas markets through multiple pipeline interconnections as well as low pressure service where necessary to enable customers to economically and efficiently produce their wells.

We believe we provide superior service to our customers as demonstrated by:

- Our willingness to incur upfront capital expenditures to fund pipeline extensions, well connections and increased compression.
- Our ability to respond quickly on new well connections to enable our customers to bring their wells on production in an efficient manner.
- Our flexibility to structure competitive and innovative natural gas purchase, gathering and processing contracts for our customers.

Favorable commercial agreements that reduce commodity price risk. Substantially all of the operating income generated by NOARK s transmission and gathering assets is generated under fixed-fee agreements. We derive substantially all of the operating income from our gathering and processing operations from fee based and percentage-of-proceeds arrangements. We have hedged a significant amount of our near term equity natural gas production and equity NGL production from our processing operations, which we believe should reduce volatility in our operating income. In our Mid-Continent operations, we have an active hedging program to mitigate a portion of the commodity price risk associated with our percentage-of-proceeds and keep-whole contracts. Furthermore, we are able to mitigate the commodity price risk often associated with keep-whole contracts during periods of unfavorable processing margins by bypassing our Elk City processing plant and delivering the natural gas directly into connecting pipelines since the natural gas gathered by the Elk City plant does not require processing to meet pipeline quality specifications. In our Appalachian operations, we are the beneficiary of natural gas gathering agreements with Atlas America under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport. We are the beneficiary of, and consult with Atlas America with respect to, the hedging program Atlas America has established for its Appalachian natural gas production that mitigates the risks of our percentage-of-proceeds agreement with it.

Experienced management and engineering team. Through our general partner we have significant management and technical expertise. Our senior management team averages approximately 20 years of experience in the oil and natural gas industry and currently manages 91 public and private drilling investment partnerships. Our operational and technical expertise has enabled us to identify assets that have not been fully utilized and to improve their performance upon integration into our operations. The technical team includes degreed pipeline, geological and processing engineers, and environmental, safety, title and rights of way specialists who average over 20 years of experience in the construction and operation of pipeline systems. In addition, upon completion of our acquisition of Spectrum, members of Spectrum s senior management team became Atlas America employees and continue to manage the Mid-Continent operations while assisting us in our efforts to grow other parts of our business. The Mid-Continent senior management team averages over 20 years of experience in all facets of the midstream natural gas industry.

The Midstream Natural Gas Gathering, Processing and Transmission Industry

The midstream natural gas gathering and processing industry is characterized by regional competition based on the proximity of gathering systems and processing plants to producing natural gas wells.

The natural gas gathering process begins with the drilling of wells into natural gas or oil bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems

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generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells.

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

Natural gas transmission pipelines receive natural gas from producers, other mainline transmission pipelines, shippers and gathering systems through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial end-users, utilities and other pipelines. Generally natural gas transmission agreements generate revenue for these systems based on a fee per unit of volume transported.

Our Mid-Continent Operations

We own and operate a 565-mile interstate natural gas pipeline, approximately 2,565 miles of intrastate natural gas gathering systems, including approximately 800 miles of inactive pipeline, located in Oklahoma, Arkansas, southeast Missouri, northern Texas and the Texas panhandle, and two processing plants and one stand-alone treating facility in Oklahoma. Our Mid-Continent operations were formed through our acquisition of Spectrum in July 2004 and expanded through our Elk City acquisition in April 2005 and the NOARK acquisition in October 2005. Ozark Gas Transmission transports natural gas from receipt points in eastern Oklahoma, including major intrastate pipelines, and western Arkansas, where the Arkoma Basin is located, to local distribution companies in Arkansas and Missouri and to interstate pipelines in northeastern and central Arkansas. Ozark Gas Gathering provides access to natural gas supplies that are then transported through Ozark Gas Transmission. Our gathering and processing assets service long-lived natural gas basins that continue to experience an increase in drilling activity, including the Anadarko Basin and the Arkoma Basin and the Golden Trend area of Oklahoma. Our systems gather natural gas from oil and natural gas wells and process the raw natural gas into merchantable, or residue gas, by extracting NGLs and removing impurities. In the aggregate, our Mid-Continent systems have approximately 1,160 receipt points, consisting primarily of individual connections and, secondarily, of central delivery points which are linked to multiple wells. Our gathering systems currently connect with interstate and intrastate pipelines operated by Ozark Gas Transmission, ONEOK Gas Transportation, LLC, Southern Star Central Gas Pipeline, Inc., Panhandle Eastern Pipe Line Company, LP, Northern Natural Gas Company, CenterPoint Energy, Inc., ANR Pipeline Company, Texas Eastern, Mississippi River Transmission and Natural Gas Pipeline Company of America.

Mid-Continent Overview

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

According to the Energy Information Administration, Oklahoma accounted for approximately 9.0% of total 2003 domestic natural gas production, or 1.6 Tcf. From 2000 to 2003, Oklahoma reserves, which were 15.4 Tcf

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at December 31, 2003, grew at an annual compound growth rate of 4.0%, significantly higher than total domestic reserves which grew at a rate of 2.1%. From 2000 to 2004, natural gas production in Oklahoma has grown at a compound annual rate of 1.2% while domestic natural gas production as a whole decreased at a compound annual rate of 0.5%.

The number of active drilling rigs serving Oklahoma has increased significantly over the last three years. In 2004, the number of active rigs drilling in Oklahoma averaged 159 or a 75% increase over 2002. The areas served by our Velma, Elk City and NOARK assets have also experienced an increase in oil and natural gas development as evidenced by a growth in well completions in the counties that the Elk City system, Velma system and NOARK system serve. In 2004, well permits in Carter, Garvin, Grady, Stephens, Beckham and Washita counties totaled 809, a 20% increase compared to 2002.

FERC-Regulated Transmission System

We own a 75% interest in NOARK, which owns a 565-mile FERC-regulated natural gas interstate pipeline extending from southeast Oklahoma through Arkansas and into southeast Missouri. Ozark Gas Transmission delivers natural gas via 30 supply and delivery interconnects with major intrastate and interstate pipelines, including Mississippi River Transmission Corp., Natural Gas Pipeline Company of America and Texas Eastern Transmission Corp., and receives natural gas from eight interconnects with intrastate pipelines, including Enogex, BP s Vastar gathering system, Arkansas Oklahoma Gas Corporation, Arkansas Western Gas Company and ONEOK Gas Transmission. Ozark Gas Transmission recently entered into a firm transportation agreement with Southwestern Energy Services Company under which Southwestern Energy Services has reserved capacity for 15,000 MMbtu/d through October 31, 2006.

Mid-Continent Gathering Systems

Velma. The Velma gathering system is located in the Golden Trend area of Southern Oklahoma and the Barnett Shale area of North Texas. As of September 30, 2005, the gathering system had approximately 1,100 miles of active pipeline with approximately 580 receipt points consisting primarily of individual connections and, secondarily, of central delivery points which are linked to multiple wells. The system includes approximately 800 miles of inactive pipeline, much of which can be returned to active status as local drilling activity warrants.

Elk City. The Elk City gathering system includes approximately 300 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma. The Elk City gathering system connects to over 300 receipt points, with a majority of the western end of the system located in close proximity to areas of high drilling activity. We recently completed three new gathering and compression projects which will increase gathered volumes and, we believe, have a significant positive effect on our earnings.

NOARK Gas Gathering. NOARK owns Ozark Gas Gathering, 365 miles of intrastate natural gas gathering pipeline located in eastern Oklahoma and western Arkansas, providing access to both the well-established Arkoma basin and the newly-exploited Fayetteville Shale. This system connects to approximately 250 receipt points and compresses and transports gas to interconnections with Ozark Gas Transmission.

Processing Plants

Velma. The Velma processing plant, located in Stephens County, Oklahoma, is a single-train twin-expander cryogenic facility with a natural gas capacity of approximately 100 MMcf/d. The Velma plant is one of only two facilities in the area that is capable of treating both high-content hydrogen sulfide and carbon dioxide gas. We sell natural gas to purchasers at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbons Company. Our Velma operations gather and process natural gas for approximately 150 producers. We have made capital expenditures at the facility to improve its efficiency and competitiveness, including by implementing electric-powered compressors rather than higher-cost natural gas-powered compressors used by many of our competitors, which results in higher revenues from higher efficiency and lower fuel costs. In addition, we recently completed a $6.0 million compression expansion project that increased processing capacity by 30 MMcf/d.

Elk City. The Elk City processing plant, located in Beckham County, Oklahoma, is a twin-train cryogenic natural gas processing plant with a total capacity of approximately 130 MMcf/d. We sell natural gas to purchasers at the tailgate of our Elk City processing plant and sell NGL production to ONEOK Hydrocarbons Company. The Prentiss treating facility, also located in Beckham County, is an amine treating facility with a total capacity of approximately 200 MMcf/d. Our Elk City operations gather and process gas for more than 135 producers.

We plan to complete construction of the Sweetwater gas processing facility near our Prentiss treatment plant by mid-2006. The new plant will initially be scaled to 120 MMcf/d of processing capacity. Along with the plant, we will construct a gathering system to be located primarily in Beckham and Roger Mills counties in Oklahoma and Hemphill County, Texas. We anticipate that construction of the plant and associated gathering system will cost approximately $40.0 million and generate cash flow of $8.0 million to $10.0 million annually.

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

NOARK Partnership

NOARK is an Arkansas limited partnership in which Atlas Arkansas owns a 74% general partner interest and a 1% limited partner interest and Southwestern owns a 25% general partner interest. The current configuration of NOARK s assets was completed in 1998 when Enogex acquired its interest in the partnership, which at that point owned Ozark Gas Gathering, and acquired Ozark Gas Transmission and certain Warren Petroleum gathering assets and contributed them to the partnership.

The partnership is managed by a five-member management committee comprised of the partnership s project leader appointed by Atlas Arkansas, subject to Southwestern s consent which cannot be unreasonably withheld, two members appointed by Atlas Arkansas and two members appointed by Southwestern. The management committee determines whether to distribute cash, may issue mandatory capital calls to the partners and may conduct expansion projects. An expansion to the system not included in an approved budget requires an 80% vote of the partners; if a partner does not consent to an expansion within 30 days, the other partner may fund the project and receive a cash distribution equal to all of the net operating income attributable to the project until it has received 200% of its capital contribution, before the non-consenting partner receives distributions attributable to the project.

Under the partnership agreement, day-to-day management of the partnership s operations is the responsibility of the project leader, who will be an employee of Atlas America. Atlas Arkansas has the sole power to remove the project leader and, upon a vacancy in that position, to propose a new project leader, subject to the consent of Southwestern, not to be unreasonably withheld.

As described under NOARK Notes, NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., currently has outstanding $66.0 million in principal amount of 7.15% notes due in 2018. Liability under the notes is allocated 40% to Enogex and 60% to Southwestern, and the parties are several guarantors for their respective allocations. As part of the NOARK acquisition, Enogex agreed to redeem its portion of the notes as promptly as practicable after the closing. We expect that the redemption of $26.4 million of the notes will be completed on December 5, 2005. After the redemption, $39.6 million of notes will remain outstanding, for which Southwestern will remain liable. Under the partnership agreement, interest and principal payments on the notes will be made from amounts otherwise distributable to Southwestern and, if that amount is insufficient, Southwestern is required to make a capital contribution to NOARK. NOARK distributes cash available for distribution after amounts payable on the notes to the partners in accordance with their percentage interests.

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Natural Gas Supply

In the Mid-Continent, we have gas purchase, gathering and processing agreements with approximately 250 producers with terms ranging from one month to 15 years. These agreements provide for the purchase or gathering of gas under fixed-fee, percentage-of-proceeds or keep-whole arrangements. Most of the agreements provide for compression, treating, and/or low volume fees. Producers generally provide, in-kind, their proportionate share of compressor fuel required to gather the gas and to operate the Velma and Elk City processing plants. In addition, the producers generally bear their proportionate share of gathering system line loss and, except for keep-whole arrangements, bear gas plant shrinkage, or the gas consumed in the production of NGL.

We have enjoyed long-term relationships with the majority of our Mid-Continent producers. For instance, on the Velma system, where we have producer relationships going back over 20 years, our top four producers, which accounted for approximately 60% of our Velma volumes for the year ended December 31, 2004, have recently executed renegotiated contracts with primary terms running into 2009 and 2010. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions.

Natural Gas and NGL Marketing

We sell natural gas to purchasers at the tailgate of both the Velma and Elk City plants and at various delivery points on Ozark Gas Gathering. During the year ended December 31, 2004, in our Velma operations, ONEOK Energy Marketing and Trading accounted for 31% of our residue natural gas sales and Tenaska Marketing Ventures accounted for 12% of such sales. We currently sell the majority of our residue natural gas at the average of ONEOK Gas Transportation, LLC and Southern Star Central Gas Pipeline first-of-month indices as published in Inside FERC. The Velma plant has access to ONEOK Gas Transportation, an intrastate pipeline, and Southern Star Central Gas Pipeline, an interstate pipeline. In our Elk City operations, we sell substantially all of our residue gas to ONEOK Energy Marketing, at first-of-month index pricing. The Elk City plant has access to five major interstate and intrastate downstream pipelines: Natural Gas Pipe Line of America, Panhandle Eastern Pipeline Co., CenterPoint Energy Gas Transmission Company, Northern Natural Gas Company and Enogex. Ozark Gas Gathering gas prices are generally based on Texas Eastern East LA index as published in Inside FERC and have historically been sold to affiliates of Enogex and Southwestern.

We sell our NGL production to ONEOK Hydrocarbons Company under two separate agreements. Under the Velma agreement, we have the right to elect on a monthly basis until January 31, 2006 whether the NGLs are sold into the Mont Belvieu or Conway markets. After that, NGLs will be sold on a 50% Mont Belvieu/50% Conway combined price. NGLs are priced at the average monthly Oil Price Information Service, or OPIS, price for the selected market. The Velma agreement has an initial term expiring February 1, 2011. NGL production from our Elk City plant is also sold to ONEOK Hydrocarbons Company based on Conway OPIS postings. The Elk City agreement has an initial term expiring October 1, 2008.

Condensate is collected at the Velma gas plant and around the Velma gathering system and sold for our account to SemGroup, L.P. and EnerWest Trading while that collected at Elk City is sold to TEPPCO Crude Oil, L.P.

Natural Gas and NGL Hedging

Our Mid-Continent operations are exposed to certain commodity price risks. These risks result from either taking title to natural gas and NGLs, including condensate, or being obligated to purchase natural gas to satisfy contractual obligations with certain producers. We mitigate a portion of these risks through a comprehensive risk management program which employs a variety of hedging tools. The resulting combination of the underlying physical business and the financial risk management program is a conversion from a physical environment that consists of floating prices to a risk-managed environment that is characterized by fixed prices.

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

We are exposed to commodity price risks when natural gas is purchased for processing. The amount and character of this price risk is a function of our contractual relationships with natural gas producers, or, alternatively, a function of cost of sales. We are therefore exposed to price risk at a gross profit level rather than revenue level. These cost-of-sales or contractual relationships are generally of two types:

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

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

We hedge a portion of these risks by using fixed-for-floating swaps, which result in a fixed price, or by utilizing the purchase or sale of options, which result in a range of fixed prices.

We recognize gains and losses from the settlement of our hedges in revenue when we sell the associated physical residue natural gas or NGLs. Any gain or loss realized as a result of hedging is substantially offset in the market when we sell the physical residue natural gas or NGLs. All of our hedges are characterized as cash flow hedges as defined in SFAS No. 133, Accounting for Derivative Instruments and Hedging Accounting. We determine gains or losses on open and closed hedging transactions as the difference between the hedge price and the physical price. This mark-to-market methodology uses daily closing NYMEX prices when applicable and an internally-generated algorithm for hedged commodities that are not traded on a market. To insure that these financial instruments will be used solely for hedging price risks and not for speculative purposes, we have established a hedging committee to review our hedges for compliance with our hedging policies and procedures. In addition, we do not enter into a hedge where we cannot offset the hedge with physical residue natural gas or NGL sales.

As of September 30, 2005, we had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Fixed-Price Swaps

Twelve month period ended September 30,	Volumes	Average fixed price	Fair value liability(1)
	(gallons)	(per gallon)	(in thousands)
2006	38,586,000	$ 0.673	$ (16,742)
2007	38,115,000	0.711	(12,188)
2008	34,587,000	0.702	(9,037)
2009	7,434,000	0.697	(1,781)
			$ (39,748)

Natural Gas Fixed-Price Swaps

Twelve month period ended September 30,	Volumes	Average fixed price	Fair value liability(2)
	(MMbtu)	(per MMbtu)	(in thousands)
2006	3,923,000	$ 7.169	$ (5,767)
2007	1,560,000	7.210	(1,658)
2008	510,000	7.262	(1,037)
			$ (8,462)

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Natural Gas Basis Swaps

Twelve month period ended September 30,	Volumes	Average fixed price	Fair value liability(1)
	(MMbtu)	(per MMbtu)	(in thousands)
2006	4,262,000	$ -0.517	$ 1,376
2007	1,560,000	-0.522	1,584
2008	510,000	-0.544	1,383
			$ 4,343

Crude Oil Fixed-Price Swaps

Twelve month period ended September 30,	Volumes	Average fixed price	Fair value liability(2)
	(Bbls)	(per Bbl)	(in thousands)
2006	67,800	$ 51.329	$ (1,056)
2007	80,400	55.187	(844)
2008	82,500	58.475	(414)
			$ (2,314)

Crude Oil Options

Twelve month period ended September 30,	Option type	Volumes	Average strike price	Fair value liability(2)
		(Bbls)	(per Bbls)	(in thousands)
2006	Puts purchased	15,000	$ 30.00	$
2006	Calls sold	15,000	34.25	(481)
				$ (481)
			Total liability	$ (46,662)

(1) Fair value based on our internal model which forecasts forward natural gas liquid prices as a function of forward NYMEX natural gas and light crude prices.

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

Our Appalachian Basin Operations

We own and operate approximately 1,500 miles of intrastate gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Our Appalachian operations serve approximately 5,100 wells with an average throughput of 54.8 MMcf/d of natural gas for the nine months ended September 30, 2005. Our gathering systems provide a means through which well owners and operators can transport the natural gas produced by their wells to interstate and public utility pipelines for delivery to customers. To a lesser extent, our gathering systems transport natural gas directly to customers. Our gathering systems connect with public utility pipelines operated by Peoples Natural Gas Company, National Fuel Gas Supply, Tennessee Gas Pipeline Company, National Fuel Gas Distribution Company, East Ohio Gas Company, Columbia Gas of Ohio, Consolidated Natural Gas Co., Texas Eastern Pipeline, Columbia Gas Transmission Corp., Equitrans Pipeline Company, Gatherco Incorporated and Equitable Utilities. Our systems are strategically located in the Appalachian Basin, a region characterized by long-lived, predictable natural gas reserves that are close to major eastern U.S. markets.

Appalachian Basin Overview

The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee. It is the most mature oil and gas producing region in the United States, having established the first oil production in 1859. In addition, the Appalachian Basin is strategically located near the energy-consuming regions of the mid-Atlantic and northeastern United States which has historically resulted in Appalachian producers selling their natural gas at a premium to the benchmark price for natural gas on the NYMEX.

According to the Energy Information Administration, a branch of the U.S. Department of Energy, in 2003 there were 22.4 Tcf of natural gas consumed in the United States which represented approximately 22.9% of the total energy used. The Appalachian Basin accounted for approximately 3.3% of total 2003 domestic natural gas production, or 647.9 Bcf. Additionally, in 2003 there were approximately 145,189 gas wells in the Appalachian Basin which represented roughly 36.9% of the total number of gas wells in the United States. Of those wells, Atlas America and its drilling investment partnerships own interests in approximately 5,755 proved developed producing wells, 84% of which Atlas America operated in 2004.

Furthermore, according to the Natural Gas Annual 2003, an annual report published by the Energy Information Administration, Office of Oil and Gas, the Appalachian Basin holds 10.9 Tcf of economically recoverable gas reserves, representing approximately 5.8% of total domestic reserves as of December 31, 2003. World Oil magazine, in its February 2005 issue, predicted that approximately 5,316 oil and gas wells will be drilled in the Appalachian Basin during 2005, approximately 13.3% of the total number of wells they predict will be drilled in the United States during 2005, and an increase of 8% over the number of Appalachian Basin wells estimated to have been drilled during 2004, compared to an increase of 7.2% in the wells drilled in the United States from 2004 to 2005.

Natural Gas Supply

Substantially all of the natural gas we transport in the Appalachian Basin is derived from wells operated by Atlas America, a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin. Atlas America is the corporate parent of our general partner and, through it, has a 2% general partner interest and will have a 13.3% limited partner interest in us after this offering. We are party to an omnibus agreement with Atlas America which is intended to maximize the use and expansion of our gathering systems and the amount of natural gas which we transport in the region. Among other things, the omnibus agreement requires Atlas America to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. Atlas America can require us to extend our lines to connect an Atlas America-operated well located more than 2,500 feet from our gathering system if it extends a flow line to within 1,000 feet; for other Atlas America-operated wells located more than 2,500 feet from our gathering systems, we have a right to extend our lines. We are also party to natural gas gathering agreements with Atlas America under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport. From the inception of our operations in January 2000 through September 30, 2005, we connected 2,040 new wells to our Appalachian gathering system, 433 of which were added through acquisitions of other gathering systems. For the three months ended September 30, 2005, we connected 151 wells to our gathering system and for the 12 months ended September 30, 2005, we connected 442 wells. Our ability to increase the flow of natural gas through our gathering systems and to offset the natural decline of the production already connected to our gathering systems will be determined primarily by the number of wells drilled by Atlas America and connected to our gathering systems and by our ability to acquire additional gathering assets.

Natural Gas Revenues

Our Appalachian Basin revenues are determined primarily by the amount of natural gas flowing through our gathering systems and the price received for this natural gas. We have an agreement with Atlas America under which it pays us gathering fees generally equal to a percentage, typically 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 Mcf. During the year ended December 31, 2004, we received gathering fees averaging $0.96 per Mcf and for the nine months ended September 30, 2005, we received gathering fees averaging $1.10 per Mcf. We charge other

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operators fees negotiated at the time we connect their wells to our gathering systems or, in a pipeline acquisition, that were established by the entity from which we acquired the pipeline.

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

Our Relationship with Atlas America

We began our operations in January 2000 by acquiring the gathering systems of Atlas America. Atlas America will own a 13.3% limited partner interest and a 2% general partner interest in us after this offering through its ownership of our general partner, Atlas Pipeline Partners GP. Atlas America and its affiliates sponsor limited and general partnerships to raise funds from investors to explore for, develop and produce natural gas and, to a lesser extent, oil from locations in eastern Ohio, western New York and western Pennsylvania. Our gathering systems are connected to approximately 4,550 wells developed and operated by Atlas America in the Appalachian Basin. Through agreements between us and Atlas America, we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas America.

Omnibus Agreement

Under the omnibus agreement, Atlas America and its affiliates agreed to add wells to the gathering systems and provide consulting services when we construct new gathering systems or extend existing systems. The omnibus agreement also imposes conditions upon our general partner s disposition of its general partner interest in us. The omnibus agreement is a continuing obligation, having no specified term or provisions regarding termination except for a provision terminating the agreement if our general partner is removed as general partner without cause. The omnibus agreement may not be amended without the approval of the conflicts committee of the managing board of our general partner if, in the reasonable discretion of our general partner, such amendment will adversely affect the common unitholders. Unitholders do not have explicit rights to approve any termination or material modification of the omnibus agreement, as stated in the accompanying prospectus under Our Partnership Agreement Limited Voting Rights. We anticipate that the conflicts committee would submit to the common unitholders for their approval any proposal to terminate or amend the omnibus agreement if our general partner determines, in its reasonable discretion, that the termination or amendment would materially adversely affect our common unitholders.

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

Consulting Services. The omnibus agreement requires Atlas America to assist us in identifying existing gathering systems for possible acquisition and to provide consulting services to us in evaluating and making a bid for these systems. Atlas America must give us notice of identification by it or any of its affiliates of any gathering system as a potential acquisition candidate, and must provide us with information about the gathering system, its seller and the proposed sales price, as well as any other information or analyses compiled by Atlas America with respect to the gathering system. We will have 30 days to determine whether we want to acquire the identified system and advise Atlas America of our intent. If we intend to acquire the system, we have an additional 60 days to complete the acquisition. If we do not complete the acquisition, or advise Atlas America that we do not intend to acquire the system, then Atlas America may do so.

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

Disposition of Interest in Our General Partner. Direct and indirect wholly-owned subsidiaries of Atlas America act as the general partners, operators or managers of the drilling investment partnerships sponsored by Atlas America. Our general partner is a subsidiary of Atlas America. Under the omnibus agreement, those subsidiaries, including our general partner, that currently act as the general partners, operators or managers of partnerships sponsored by Atlas America must also act as the general partners, operators or managers for all new drilling investment partnerships sponsored by Atlas America. Atlas America and its affiliates may not divest their ownership of our general partner entity without divesting their ownership of the other entities to the same acquirer, except that Atlas America is permitted to transfer its interest in our general partner to a wholly- or majority-owned direct or indirect subsidiary as long as Atlas America continues to control the new entity. For these purposes, divestiture means a sale of all or substantially all of the assets of an entity, the disposition of more than 50% of the capital stock or equity interest of an entity, or a merger or consolidation that results in Atlas America and its affiliates, on a combined basis, owning, directly or indirectly, less than 50% of the entity s capital stock or equity interest, but excludes pledges to a lender in connection with a secured funding arrangement. Our general partner has pledged its interests in us as security for the revolving credit facility of Atlas America.

Atlas America has recently announced that it is considering transferring its ownership interest in our general partner to a new wholly-owned subsidiary and then making a registered, initial public offering of a minority interest in the subsidiary. **This prospectus supplement does not constitute an offer to sell or a solicitation of an offer to buy any such securities.**

Natural Gas Gathering Agreements

Under the master natural gas gathering agreement, we receive a fee from Atlas America for gathering natural gas, determined as follows:

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

- for (i) natural gas from well interests allocable to general and limited partnerships sponsored by Atlas America that drill wells on or after December 1, 1999 that are connected to our gathering systems (ii) natural gas from well interests allocable to Atlas America or its affiliates (excluding general or limited partnerships sponsored by them) that are connected to our gathering systems after February 2, 2000, and (iii) well interests allocable to third parties in wells connected to our gathering systems at February 2, 2000, the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported; and for natural gas from well interests operated by Atlas America and drilled after December 1, 1999 that are connected to a gathering system that is not owned by us and for which we assume the cost of constructing the connection to that gathering system, an amount equal to the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported, less the gathering fee charged by the other gathering system.

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

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

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

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

We recently amended the gas gathering agreements with Atlas America to provide that the gross sales price, for purposes of the agreements, will mean the price that is actually received, adjusted to take into account proceeds received or payments made pursuant to financial hedging arrangements.

Credit Facility

Concurrently with the completion of the Elk City acquisition, in April 2005, we entered into a $270.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association, that replaced our $135.0 million facility. The facility originally included a $225.0 million five-year revolving line of credit and a $45.0 million five-year term loan. Concurrently with the completion of the NOARK acquisition, the facility was increased to $400.0 million. 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 credit facility requires us to maintain a ratio of senior secured debt to EBITDA of not more than 6.0 to 1.0, reducing to 5.75 to 1.0 on March 31, 2006, 4.5 to 1.0 on June 30, 2006 and 4.0 to 1.0 on September 30, 2006; a funded debt to EBITDA ratio of not more than 6.0 to 1.0, reducing to 5.75 to 1.0 on March 31, 2006 and to 4.5 to 1.0 on June 30, 2006; and an interest coverage ratio of not less than 2.5 to 1.0, increasing to 3.0 to 1.0 on March 31, 2005. The credit facility defines EBITDA to include pro forma adjustments, acceptable to Wachovia Bank, National Association, as administrator of the facility, following material acquisitions. This calculation of EBITDA for purposes of our credit facility differs materially from the calculation set forth in Summary Summary Historical Consolidated Financial and Other Data. As of September 30, 2005, pro forma for our acquisition of NOARK, our ratio of senior secured debt to EBITDA was 5.4 to 1.0, our funded debt ratio was 5.4 to 1.0 and our interest coverage ratio was 2.8 to 1.0. In addition, we are required to prepay $175.0 million with

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the net proceeds of any asset sales or issuances of debt or equity and thereafter to the extent our ratio of senior secured debt to EBITDA exceeds 4.0 to 1.0, except that, following mandatory prepayments of $100.0 million, we are permitted to use up to $40.0 million of net proceeds from equity issuances to fund construction of the Sweetwater plant. Credit availability under the credit facility will be reduced by the amount of mandatory prepayments. We intend to use the net proceeds of this offering to prepay amounts outstanding as required by this provision, which will reduce credit availability by $100.0 million.

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. We are permitted to have up to $275.0 million of senior unsecured debt and up to $500,000 in other debt. 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.

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

NOARK Notes

NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., currently has outstanding $66.0 million in principal amount of 7.15% notes due in 2018. The notes are governed by an indenture dated June 1, 1998 for which UMB Bank, N.A. serves as trustee. Interest on the notes is payable semi-annually, in cash, in arrears on June 1 and December 1 of each year. Liability under the notes is allocated severally 40% to Enogex and 60% to Southwestern, and the parties are several guarantors for their respective allocations.

The notes are subject to a semi-annual redemption in installments of $1.0 million each at a redemption price of 100% of the principal, plus accrued and unpaid interest. Additionally, at the option of either Enogex or Southwestern, notes in an aggregate principal amount guaranteed by either company as of a particular payment date may be redeemed at such notes redemption price plus a make-whole premium and unpaid interest accrued to that date by giving the trustee at least 60 days notice. As part of the NOARK acquisition, Enogex agreed to redeem its portion of the notes as promptly as practicable after the closing, and at the closing it deposited cash sufficient to redeem the notes into an escrow account. We expect that the redemption of $26.4 million of the notes will be completed on December 5, 2005. After the redemption, $39.6 million of notes will remain outstanding, for which Southwestern will remain liable. Under the partnership agreement, payments on the notes will be made from amounts otherwise distributable to Southwestern and, if that amount is insufficient, Southwestern is required to make a capital contribution to NOARK. NOARK distributes cash available for distribution to the partners, after amounts payable on their respective allocations of the notes, in accordance with their percentage interests.

Competition

Acquisitions. We have encountered competition in acquiring midstream assets owned by third parties. In several instances we submitted bids in auction situations and in direct negotiations for the acquisition of such assets and were either outbid by others or were unwilling to meet the sellers expectations. In the future, we expect to encounter equal if not greater competition for midstream assets because, as natural gas, crude oil and NGL prices increase, the economic attractiveness of owning such assets increases.

Mid-Continent. In our Mid-Continent service area, we compete for the acquisition of well connections with several other gathering/servicing operations. These operations include plants and gathering systems operated by

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Duke Energy Field Services, ONEOK Field Services and Enbridge. We believe that the principal factors upon which competition for new well connections is based are:

- the price received by an operator or producer for its production after deduction of allocable charges, principally the use of the natural gas to operate compressors; and
- responsiveness to a well operator s needs, particularly the speed at which a new well is connected by the gatherer to its system.

We believe that our 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 and that we present an attractive alternative for producers. However, if we cannot compete successfully, we may be unable to obtain new well connections and, possibly, could lose wells already connected to our systems.

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

Appalachian Basin. Our Appalachian Basin operations do not encounter direct competition in their service areas since Atlas 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 17 third party wells and for the first nine months of 2005 we connected 16 third party wells.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. FERC regulates our interstate natural gas pipeline interests. Through Atlas Arkansas, we own a 75% interest in NOARK, which owns Ozark Gas Transmission. Ozark Gas Transmission transports natural gas in interstate commerce. As a result, Ozark Gas Transmission qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- rate structures;

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

Under the Natural Gas Act, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters. Natural gas companies may not charge rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

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

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own a number of intrastate natural gas pipelines in New York, Pennsylvania, Ohio, Arkansas, Texas and Oklahoma that we believe would meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC and the courts.

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

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

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

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated

affiliates. For example, the Texas Railroad Commission has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of one customer over another. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. A portion of our revenues is tied to the price of natural gas. The price of natural gas is not currently subject to federal regulation and, for the most part, is not subject to state regulation. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other companies with whom we compete.

Energy Policy Act of 2005. On August 8, 2005, the Energy Policy Act of 2005 was signed into law. The Energy Policy Act contains numerous provisions relevant to the natural gas industry and to interstate pipelines in particular. Overall, the legislation attempts to increase supply sources by engaging in various studies of the overall resource base and attempting to advantage deep water production on the Outer Continental Shelf in the Gulf of Mexico. However, the primary provisions of interest to our interstate pipelines focus in two areas: (1) infrastructure development; and (2) market transparency and enhanced enforcement. Regarding infrastructure development, the Energy Policy Act includes provisions to clarify that FERC has exclusive jurisdiction over the siting of liquefied natural gas terminals; provides for market based rates for new storage facilities placed into service after the date of enactment; shortens depreciable life for gathering facilities; statutorily designates FERC as the lead agency for federal authorizations and permits; creates a consolidated record for all federal decisions relating to necessary authorizations and permits; and provides for expedited judicial review of any agency action and review by only the D.C. Circuit Court of Appeals of any alleged failure of a federal agency to act by a deadline set by FERC as lead agency. Such provisions, however, do not apply to review and authorization under the Coastal Zone Management Act of 1972. Regarding market transparency and manipulation rules, the Natural Gas Act is amended to prohibit market manipulation and add provisions for FERC to prescribe rules designed to encourage the public provision of data and reports regarding the price of natural gas in wholesale markets. The Natural Gas Act and the Natural Gas Policy Act are also amended to increase monetary criminal penalties to $1,000,000 from current law at $5,000 and to add and increase civil penalty authority to be administered by FERC to $1,000,000 per day per violation without any limitation as to total amount.

Environmental Matters

The operation of pipelines, plant and other facilities for gathering, compressing, treating, processing, or transporting natural gas, natural gas liquids and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction and operating activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operators; and
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations and that compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, we cannot assure you that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, also known as Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations we will generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be

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subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial closure operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Water Discharges. Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants is prohibited unless authorized by a permit or other agency approval. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations.

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

The DOT, through the Office of Pipeline Safety, recently finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with

specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. The Texas Railroad Commission, the Oklahoma Corporation Commission and other state agencies have adopted similar regulations applicable to intrastate gathering and transmission lines. Compliance with these existing rules has not had a material adverse effect on our operations but there is no assurance that this trend will continue in the future.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, as amended, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans, and prolonged exposure can result in death. The gas produced at our Velma gas plant contains high levels of hydrogen sulfide, and we employ numerous safety precautions at the system to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

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 manage our 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.

Properties

As of December 31, 2004, our principal facilities in Appalachia include approximately 1,500 miles of 2 to 12 inch diameter pipeline. Our principal facilities in the Mid-Continent area consist of three natural gas processing plants, one treating facility, and approximately 3,130 miles of active and inactive 2-to-42 inch diameter pipeline. Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections, 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, for wells that are currently in production; however, the leases are subject to termination if the wells cease to produce. In some of these cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. In addition, because many of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

We rent 24,959 square feet of office space through November 2009 in Tulsa, Oklahoma for our Mid-Continent operations. For a description of our natural gas processing plants, see Our Mid-Continent Operations Processing Plants.

Legal Proceedings

On March 9, 2004, the Oklahoma Tax Commission 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 are defending ourselves vigorously. We have asserted a claim for indemnification by Chevron under the provisions of our contract with it. Chevron has acknowledged our claim notice pursuant to which Chevron will be responsible for the payment of any underpayment of taxes, which would be the basis for any monetary judgment against us, but Chevron will reserve the issues of payment of penalties and reimbursement of our attorneys fees and costs for determination by arbitration following the end of the litigation. 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.

We are not subject to any other pending material legal proceedings.

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MANAGEMENT

Managing Board Members, Executive Officers and Other Key Employees

Our general partner manages our activities. Our 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 independent members of the managing board of our general partner, Messrs. Curtis Clifford and Martin Rudolph and Dr. Gayle P.W. Jackson 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). The independent board members comprise all of the members of both of the Managing Board s committees: the audit committee and the conflicts committee. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest to determine if the resolution of the conflict proposed by our general partner is fair and reasonable to us. Any matters approved by the conflicts committee are conclusively judged to be fair and reasonable to us, approved by all our partners and not a breach by our general partner or its managing board of any duties they may owe us or the unitholders. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls. The managing board has determined that the members of the audit committee meet the independence standards for audit committee members set forth in the listing standards of the NYSE, including those set forth in Rule 10A-3(b)(1) of the Securities Exchange Act, and that Mr. Rudolph qualifies as an audit committee financial expert as that term is defined in applicable rules and regulations 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	Year in which service began
Edward E. Cohen	66	Chairman of the Managing Board and Chief Executive Officer	1999
Jonathan Z. Cohen	35	Vice Chairman of the Managing Board	1999
Michael L. Staines	56	President, Chief Operating Officer and Managing Board Member	1999
Matthew A. Jones	44	Chief Financial Officer	2005
Tony C. Banks	51	Managing Board Member	1999
Curtis D. Clifford	63	Managing Board Member	2004

Gayle P.W. Jackson	59	Managing Board Member	2005
Martin Rudolph	59	Managing Board Member	2005

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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 of Resource America from 1988 to 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 since 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 a son of Edward E. Cohen.

Michael L. Staines was Senior Vice President of Resource America from 1989 to 2004 and served as a director from 1989 through 2000 and Secretary from 1989 through 1998. 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.

Matthew A. Jones has been Chief Financial Officer of Atlas America since March 2005. Mr. Jones spent the last nine years with the Investment Banking group at Friedman Billings Ramsey, most recently as Managing Director. For the last five years, Mr. Jones had been with Friedman Billings Ramsey s Energy Investment Banking Group. Before that, Mr. Jones had been associated with Friedman Billings Ramsey s Specialty Finance and Real Estate Group. Mr. Jones is a Chartered Financial Analyst.

Tony C. Banks is a Vice President of First Energy Solutions, Inc., a subsidiary of First Energy Corp., a public utility, since 2005. Mr. Banks is responsible for unregulated sales of electricity and energy-related products and services. Mr. Banks was previously the Director of Marketing for First Energy Solutions. Before that, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the Board of Optiron Corporation, which was an energy technology subsidiary of Atlas America until 2002. In addition, Mr. Banks served as President of our general partner during 2000. He was Chief Executive Officer and President of Atlas America from 1998 through 2000.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Mr. Clifford has 39 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 is a registered professional engineer in Pennsylvania.

Gayle P.W. Jackson has been President of Energy Global, Inc., a consulting firm which specializes in corporate development, diversification and government relations strategies for energy companies, since 2004. From 2001 to 2004, Dr. Jackson served as Managing Director of FE Clean Energy Group, a global private equity management firm that invests in energy companies and projects in Central and Eastern Europe, Latin America and Asia. From 1985 to 2001, Dr. Jackson was President of Gayle P.W. Jackson, Inc., a consulting firm that advised energy companies on corporate development and diversification strategies and also advised national and international governmental institutions on energy policy. Dr. Jackson has been Deputy Chairman of the Federal Reserve Bank of St. Louis since 2003 and a Board member since 2000, and is a member of the Board of Directors of Ameren Corporation, a publicly-traded public utility holding company.

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Martin Rudolph has been the Trustee of the AHP Settlement Trust, a $5 billion trust established to process litigation claims, since 2005. Before that, Mr. Rudolph was the director of tax planning, research and compliance for RSM McGladrey, Inc., a business services firm from 2001 to 2005. From 1990 to 2001, he was a Managing Partner of Rudolph, Palitz LLC, which was merged with RSM McGladrey. Mr. Rudolph is a certified public accountant.

Other Significant Employees

Robert R. Firth, 51, 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. Mr. Firth has held positions with Northern Natural Gas, Panda Resources, Transok, CMS Energy and ScissorTail Energy over his 30 years in the midstream energy sector.

David D. Hall, 48, 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.

Sean P. McGrath, 34, has been the Chief Accounting Officer of our general partner since May 2005. Before that, Mr. McGrath had been the Chief Accounting Officer of Sunoco Logistics Partners L.P., a publicly-traded partnership that transports, terminals and stores refined products and crude oil, since 2002. From 1998 to 2002, Mr. McGrath was Assistant Controller of Asplundh Tree Expert Co., a utility services and vegetation management company.

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TAX CONSIDERATIONS

General

The following summarizes material federal income tax considerations that may be relevant to a prospective unitholder who is a citizen or resident of the United States. The tax consequences of investing in us may not be the same for all investors. A careful analysis of your particular tax situation is required to analyze an investment in our common units properly. Moreover, this summary does not purport to address all aspects of taxation that may be relevant to particular unitholders, such as insurance companies, tax-exempt organizations, foreign corporations and persons who are not citizens or residents of the United States who may be subject to special treatment under federal income tax laws, except to the extent specifically discussed in this summary. As a consequence, we urge you to consult your own tax advisor.

Opinion of Tax Counsel

We have obtained an opinion from Ledgewood, our tax counsel, concerning the federal tax issues described in this section. The opinion is based on the facts described in this prospectus supplement and the accompanying prospectus. Any alteration of our activities from the description we gave to tax counsel may render the opinion unreliable.

The statements in this discussion and our counsel s opinion are based on current provisions of the Internal Revenue Code, existing, temporary and currently proposed Treasury Regulations promulgated under the Internal Revenues Code, the legislative history of the Internal Revenue Code, existing administrative rulings and practices of the IRS, and judicial decisions. Future legislative, judicial or administrative actions or decisions, which may be retroactive in effect, may cause actual tax consequences to vary substantially from those discussed in this summary. Moreover, the tax opinion represents only tax counsel s best legal judgment. It is not binding on the IRS nor does it have any other official status. We cannot assure you that the IRS will accept tax counsel s conclusions.

For the reasons set forth in the more detailed discussion as to each item, Ledgewood has not rendered an opinion with respect to the following specific federal income tax issues:

- the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (see Tax Consequences of Unit Ownership Treatment of Short Sales),
- whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (see Disposition of Common Units Allocations Between Transferors and Transferees), and
- whether our method for depreciating Section 743 adjustments is sustainable (see Disposition of Common Units Section 754 Election).

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his or her allocable share of the partnership s items of income, gain, loss and deduction in computing his or her federal income tax liability, regardless of whether cash distributions are made. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of his or her adjusted basis in the partnership interest immediately before the distribution.

Our counsel is of the opinion that we and our operating partnership will be treated as a partnership for federal income tax purposes. We have not and will not request a ruling from the IRS on this matter. Counsel s opinion is based partially upon our representations that:

neither we nor our operating partnership or any operating subsidiary has elected or will elect to be treated as an association or corporation;

we, our operating partnership and each operating subsidiary have been operated and will be operated in accordance with all applicable partnership statutes, its applicable partnership agreement or limited liability company agreement; and

for each taxable year, more than 90% of our gross income has been and will be derived from:

the exploration, development, production, processing, refining, transportation or marketing of any mineral or natural resource, including oil, gas or products thereof, or

other items of income as to which counsel has opined or will opine are qualifying income within the meaning of Section 7704(d) of the Code.

Section 7704 of the Code provides that publicly-traded partnerships such as us will, as a general rule, be taxed as corporations. However, an exception, referred to as the qualifying income exception exists if at least 90% of a publicly-traded partnership s gross income for every taxable year consists of qualifying income. Qualifying income includes income and gains derived from the transportation of crude oil, natural gas and products thereof. Other types of qualifying income include interest from other than a financial business, dividends, gains from the sale or lease of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. For this purpose, our share of the gross income earned by our operating subsidiaries will be included in our gross income as if we directly earned such income. We estimate that less than 1% of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and our general partner, and a review of the applicable legal authorities, Ledgewood is of the opinion that at least 90% of our current gross income constitutes qualifying income. Moreover, unless our business changes from that of transporting and processing natural gas, it is unlikely that we would fail to meet the 90% test in the future.

If we fail to meet the qualifying income exception, other than a failure which is determined by the IRS to be inadvertent and which is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation on the first day of the year in which we fail to meet the qualifying income exception in return for stock in that corporation, and then distributed that stock to our unitholders in liquidation of their units. This contribution and liquidation should be tax-free to us and our unitholders so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Although the tax basis of our assets is now greater than our liabilities, our tax basis will be reduced over time by depletion and depreciation deductions. If we incur substantial indebtedness in the future, it is possible that at some time in the future our liabilities may exceed our tax basis in our assets. If the deemed contribution and distribution in liquidation happened after such time, our unitholders would be taxed on the excess of our liabilities over our tax basis in our assets. Whether or not there is taxable income at the time of this event, thereafter we would be treated as a corporation for federal income tax purposes.

If we were treated as a corporation in any taxable year, either as a result of a failure to meet the qualifying income exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder s basis in his or her common units, or taxable capital gain, after his or her tax basis in his or her common units is reduced to zero. Accordingly, treatment of us as a corporation would result in a material reduction in a unitholder s cash flow and after-tax return and, thus, would likely result in a substantial reduction of the value of the common units.

The discussion below is based on the assumption that we will be treated as a partnership for federal income tax purposes.

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Limited Partner Status

Unitholders who have become our limited partners will be treated as our partners for federal income tax purposes. Counsel is also of the opinion, based upon and in reliance upon those same representations set forth under Partnership Status, that

- assignees who have executed and delivered transfer applications and are awaiting admission as limited partners, and

- unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units,

will be treated as our partners for federal income tax purposes. As there is no direct authority addressing assignees of common units who are entitled to execute and deliver transfer applications and thereby become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, Counsel s opinion does not extend to these persons. Furthermore, a purchaser or other transferee of common units who does not execute and deliver a transfer application may not receive some federal income tax information or reports furnished to record holders of common units unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those common units.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his or her status as a partner with respect to such units for federal income tax purposes. See Tax Consequences of Unit Ownership-Treatment of Short Sales.

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These holders should consult their own tax advisors with respect to their status as our partners for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-through of Taxable Income. We do not pay any federal income tax. Instead, each unitholder is required to report on his or her income tax return his or her allocable share of our income, gains, losses and deductions without regard to whether we make cash distributions to that unitholder. Consequently, we may allocate income to our unitholders although we have made no cash distribution to them. Each unitholder will be required to include in income his or her allocable share of our income, gain, loss and deduction for our taxable year ending with or within his or her taxable year.

Treatment of Distributions. Our distributions generally will not be taxable for federal income tax purposes to the extent of a unitholder s tax basis in his or her common units immediately before the distribution. Our cash distributions in excess of that tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under Disposition of Common Units below. Any reduction in a unitholder s share of our liabilities for which no partner, including our general partner, bears the economic risk of loss, known as nonrecourse liabilities, will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder s at risk amount to be less than zero at the end of any taxable year, the unitholder must recapture any losses deducted in previous years. See Limitations on Deductibility of Our Losses.

A decrease in a unitholder s percentage interest in us because of our issuance of additional common units will decrease his or her share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his or her tax basis in our common units, if the distribution reduces his or her share of our unrealized receivables, including depreciation recapture, or substantially appreciated inventory items, both as defined in Section 751 of the Internal Revenue Code, known collectively as Section 751 assets. To that extent, a unitholder will be treated as having been distributed his or her proportionate share of the Section 751 assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him or her. This latter deemed exchange will generally result in the unitholder s realization of ordinary income under Section 751(b) of the Internal Revenue Code. That income will equal the excess of:

- the non-pro rata portion of that distribution over

- his or her tax basis for the share of Section 751 assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions. We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through December 31, 2007 will be allocated an amount of federal taxable income for that period that will be less than 20% of the cash distributed with respect to that period. We anticipate that after the taxable year ending December 31, 2007, the ratio of taxable income to cash distributions will increase. These estimates are based upon assumptions with respect to gross income from operations, capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. The actual taxable income that will be allocated as a percentage of distributions could be higher or lower than our estimate of less than 20%, and any difference could be material and could materially affect the value of the common units.

For example, the ratio of allocable taxable income to cash distributions could be greater, and perhaps substantially greater, than 20% with respect to the period described above if:

- gross income from operations exceeds the amount required to make the minimum quarterly distribution on all units, yet we only distribute the minimum quarterly distribution on all units or

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering.

In prior taxable years, unitholders received cash distributions that exceeded the amount of taxable income allocated to the unitholders. This excess was partially the result of depreciation deductions, but was primarily the result of special allocations to our general partner of taxable income earned by our operating subsidiary which caused a corresponding reduction in the amount of taxable income allocable to us. Our general partner has agreed to receive additional special allocations of taxable income as follows:

- For 2005, the lesser of $2,400,000 or the amount necessary to make the ratio of taxable income of all unitholders who own units throughout 2005 to the cash received by such unitholders with respect to 2005 not higher than 39%.

- For 2006, the lesser of $2,800,000 or the amount necessary to make the ratio of taxable income of all unitholders who own units throughout 2006 to the cash received by such unitholders with respect to 2006 not higher than 39%.

Since these special allocations increase our general partner s capital account, the distribution it will receive upon our liquidation will be increased and distributions to unitholders will be correspondingly reduced. It is possible that upon liquidation common unitholders will recognize taxable income in excess of liquidation distributions.

Tax Rates. In general the highest effective United States federal income tax rate for individuals is currently 35% and the maximum United States federal income tax rate for net capital gains of an individual is currently 15% if the asset disposed of was held for more than 12 months at the time of disposition.

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Alternative Minimum Tax. Although we do not expect to generate significant tax preference items or adjustments, each unitholder will be required to take into account his distributive share of any items of our income, gain, deduction or loss for purposes of the alternative minimum tax.

Basis of Common Units. A unitholder s initial tax basis for his or her common units will be the amount he or she paid for the common units plus his or her share of our nonrecourse liabilities. That basis will be increased by his or her share of our income and by any increases in his or her share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by our distributions to him or her, by his or her share of our losses, by any decreases in his or her share of our nonrecourse liabilities and by his or her share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized.

Limitations on Deductibility of Our Losses. The deduction by a unitholder of his or her share of our losses will be limited to the tax basis in his or her units and, in the case of an individual unitholder or a corporate unitholder that is subject to the at risk rules (for example, if more than 50% of the value of its stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations), to the amount for which the unitholder is considered to be at risk with respect to our activities, if that is less than its tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his or her units, excluding any portion of that basis attributable to his or her share of our nonrecourse liabilities, reduced by any amount of money he or she borrows to acquire or hold the units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder s at risk amount will increase or decrease as the tax basis of the unitholder s units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his or her share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally activities in which the taxpayer does not materially participate, only to the extent of the taxpayer s income from those passive activities. The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or your investments in other publicly-traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder s share of our income may be deducted in full when the unitholder disposes of his or her entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder s share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly-traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer s investment interest expense is generally limited to the amount of that taxpayer s net investment income. As noted, a unitholder s share of our net passive income will be treated as investment income for this purpose. In addition, a unitholder s share of our portfolio income will be treated as investment income. Investment interest expense includes:

interest on indebtedness properly allocable to property held for investment;

- our interest expense attributed to portfolio income; and

- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder s investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment.

Allocation of Income, Gain, Loss and Deductions. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. At any time that incentive distributions are made to our general partner, gross income will be allocated to it to the extent of these distributions. In addition, for 2005 and 2006 there may be special allocations of taxable income to our general partner. See Ratio of Taxable Income to Distributions. If we have a net loss for the entire year, the amount of that loss will generally be allocated first to our general partner and the unitholders in accordance with their particular percentage interests in us to the extent of their positive capital accounts and, second, to our general partner.

As required by the Internal Revenue Code some items of our income, deduction, gain and loss will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by our general partner referred to in this discussion as contributed property, and to account for the difference between the fair market value of our assets and their carrying value on our books at the time of this offering. The effect of these allocations to a unitholder purchasing common units in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of this offering. In addition, specified items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders.

Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

Ledgewood is of the opinion that, with the exception of the issues described in Disposition of Common Units Section 754 Election and Disposition of Common Units Allocations Between Transferors and Transferees, allocations under our partnership agreement will be recognized for federal income tax purposes in determining a partner s share of an item of our income, gain, loss or deduction.

Entity-Level Collections. If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the person on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders and our general partner. We are authorized to amend the partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of a unitholder in which event he could file a claim for credit or refund.

Treatment of Short Sales. A unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of ownership of those units. If so, the unitholder would no longer

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own units for federal income tax purposes during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, deduction or loss with respect to those units would not be reportable by the unitholder;
- any cash distributions we make to that unitholder with respect to those units would be fully taxable; and
- all of those distributions would appear to be treated as ordinary income.

Unitholders desiring to assure ownership of their units for tax purposes and avoid these consequences should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. See also Disposition of Common Units Recognition of Gain or Loss. Because the IRS has not announced the results of its study and there is no authority addressing the treatment of short sales of partnership interests, Ledgewood is unable to opine on the treatment of such short sales.

Tax Treatment of Operations

Accounting Method and Taxable Year. We use the accrual method of accounting and the tax year ending December 31 for federal income tax purposes. Each unitholder must include in income his or her share of our income, gain, loss and deduction for our taxable year(s) ending within or with his or her taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31, and who disposes of all of his or her units following the close of our taxable year but before the close of his or her taxable year, must include his or her share of our income, gain, loss and deduction in income for his or her taxable year, with the result that he or she will be required to report income for his or her taxable year for his or her share of more than one year of our income, gain, loss and deduction.

Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of property contributed and the tax basis established for that property will be borne by our general partner and the unitholders. See Tax Treatment of Unitholders Allocation of Income, Gain, Loss and Deduction.

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. We are not entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property we acquire or construct is depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to our property may be required to recapture those deductions as ordinary income upon a sale of his units. See Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction and Disposition of Common Units Recognition of Gain or Loss.

Uniformity of Units. We must maintain economic and tax uniformity of the units to all holders. A lack of tax uniformity can result from a literal application of Treasury Regulation Sections 1.167(c)-1(a)(6) and 1.197-2(g)(3). Any resulting non-uniformity could have a negative impact on the value of the common units by reducing the tax deductions available to a purchaser of units. See Disposition of Common Units Section 754 Election.

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We intend to continue to depreciate or amortize the Section 743(b) adjustment attributable to unrealized appreciation in the value of contributed property in a way that will avoid non-uniformity of tax treatment among unitholders. See Disposition of Common Units Section 754 Election. If we determine that this position cannot reasonably be taken, we may adopt a different position in an effort to maintain uniformity. This could result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. The IRS may challenge any method of depreciating the Section 743(b) adjustment we adopt. If such a challenge were made and sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. See Disposition of Common Units Recognition of Gain or Loss.

Valuation of Our Properties. The federal income tax consequences of the ownership and disposition of units depends in part on our estimates of the relative fair market values of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many of the relative fair market value estimates ourselves. These estimates are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to such adjustments.

Disposition of Common Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder s tax basis in the units sold. A unitholder s amount realized will be measured by the sum of the cash or the fair market value of other property received plus his or her share of our nonrecourse liabilities. Because the amount realized includes a unitholder s share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder s tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder s tax basis in that common unit, even if the price is less than his original cost.

Should the IRS successfully contest our method of depreciating or amortizing the Section 743(b) adjustment, described under Disposition of Common Units Section 754 Election, attributable to contributed property, a unitholder could realize additional gain from the sale of units than had our method been respected. In that case, the unitholder may have been entitled to additional deductions against income in prior years but may be unable to claim them, with the result to him of greater overall taxable income than appropriate. Due to the lack of final regulations, Ledgewood is unable to opine as to the validity of the convention but believes a contest by the IRS is unlikely because a successful contest could result in substantial additional deductions to other unitholders.

Except as noted below, gain or loss recognized by a unitholder, other than a dealer in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than 12 months will generally be taxed at a maximum rate of 15%. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other unrealized receivables or to inventory items we own. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on that sale. Thus, a unitholder may recognize both ordinary income and a capital loss upon a disposition of units. Net capital loss may offset no more than $3,000 of ordinary income in the case of individuals and may only be used to offset capital gain in the case of corporations.

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The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an equitable apportionment method. Although the ruling is unclear as to how the holding period of these interests is determined once they are combined, Treasury regulations allow a selling unitholder, who can identify units transferred with an ascertainable holding period, to use the actual holding period of the units transferred. Thus, according to the ruling, a unitholder will not be able to select high or low basis common units to sell, as would be the case with corporate stock, but may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of units transferred must consistently use that identification method for all subsequent sales or exchanges of units. A unitholder considering the purchase of additional common units or a sale of common units purchased in separate transactions should consult his tax advisor as to the possible consequences of this ruling and application of the Treasury regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an appreciated partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. Our taxable income and losses are determined annually, prorated on a monthly basis and apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the New York Stock Exchange on the first business day of the month. However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business is allocated among the unitholders as of the opening of the New York Stock Exchange on the first business day of the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction accrued after the date of transfer.

The use of this method may not be permitted under existing Treasury regulations. Accordingly, Ledgewood is unable to opine on the validity of this method of allocating income and deductions between transferors and transferees of units. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder s interest, our taxable income or losses might be reallocated among the unitholders. Under our partnership agreement, we are authorized to revise our method of allocation between transferors and transferees, as well as among partners whose interests otherwise vary during a taxable period, to conform to a method permitted under future Treasury regulations.

A unitholder who owns units at any time during a quarter and who disposes of them before the record date set for a cash distribution for that quarter will be allocated a share of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Section 754 Election. We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser s tax basis in our assets (inside basis) to reflect his or her purchase price. This election does not apply to a person who purchases common units directly from us. The adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a partner s inside basis in our assets will be considered to have two components:

his or her share of our tax basis in our assets (common basis) and

his or her Section 743(b) adjustment to that basis.

Treasury regulations under Section 743 of the Internal Revenue Code require, if the remedial allocation method is adopted (which we have), a portion of the adjustment attributable to recovery property to be depreciated over the remaining cost recovery period for built-in gain. Under Treasury Regulation Section 1.167(c)-1(a)(6), an adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. A literal application of these different rules result in lack of uniformity. Under our partnership agreement, our general partner is authorized to adopt a position intended to preserve the uniformity of units even if that position is not consistent with the Treasury Regulations. See Tax Treatment of Operations Uniformity of Units.

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of property previously contributed to us, to the extent of any unamortized book-tax disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property. If this contributed property is not amortizable, we will treat that portion as non-amortizable. This method is consistent with the regulations under Section 743. This method, however, is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6) and Treasury Regulation Section 1.197-2(g)(3), neither of which is expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment exceeds that amount, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a different position which could result in lower annual depreciation or amortization deductions than would otherwise be allowable to specified unitholders. See Tax Treatment of Operations Uniformity of Units.

The allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to allocate some or all of any Section 743(b) adjustment to goodwill not so allocated by us. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets.

A Section 754 election is advantageous if the transferee s tax basis in his or her units is higher than the units share of the aggregate tax basis of our assets immediately before the transfer. In that case, as a result of the election, the transferee would have a higher tax basis in his or her share of our assets for purposes of calculating, among other items, his or her depreciation and depletion deductions and share of any gain or loss on a sale of our assets. Conversely, a Section 754 election is disadvantageous if the transferee s tax basis in his or her units is lower than the units share of the aggregate tax basis of our assets immediately before the transfer. Thus, the fair market value of the units may be affected either favorably or adversely by the election.

The calculations involved in the Section 754 election are complex and we will make them on the basis of assumptions as to the value of our assets and other matters. There is no assurance that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Notification Requirements. A unitholder who sells or exchanges units is required to notify us in writing of that sale or exchange within 30 days after the sale or exchange. We are required to notify the IRS of that transaction and to furnish information to the transferor and transferee. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker. Additionally, a transferor and a transferee of a unit will be required to furnish statements to the IRS, filed with their income tax returns for the taxable year in which the sale or exchange occurred, that describe the amount of the consideration received for the unit that is allocated to our goodwill or going concern value. Failure to satisfy these reporting obligations may lead to the imposition of substantial penalties.

Dissolutions and Terminations

Upon our dissolution, our assets will be sold and any resulting gain or loss will be allocated among our general partner and the unitholders. See Tax Consequences of Unit Ownership Allocation of Income, Gain Loss and Deductions. We will distribute all cash to our general partner and unitholders in liquidation in accordance with their positive capital account balances. See Our Partnership Agreement Cash Distribution Policy Distributions of Cash on Liquidation in the accompanying prospectus.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would result in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year might result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. See Tax Treatment of Operations Accounting Method and Taxable Year. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination could result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, nonresident aliens, foreign corporations, other foreign persons and regulated investment companies raises issues unique to those investors and, as described below, may have substantially adverse tax consequences.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our taxable income allocated to a unitholder which is a tax-exempt organization will be unrelated business taxable income and thus will be taxable to that unitholder.

A regulated investment company or mutual fund is required to derive 90% or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. The American Jobs Creation Act of 2004 generally treats income from the ownership of a qualified publicly traded partnership as qualified income to a regulated investment company. We expect that we will meet the definition of a qualified publicly traded partnership. Accordingly, we anticipate that all of our income will be treated as qualified income to a regulated investment company.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States on account of ownership of our units. As a consequence they will be required to file federal tax returns reporting their share of our income, gain, loss or deduction and pay federal income tax at regular rates on any net income or gain. Generally, a partnership is required to pay a withholding tax on the portion of the partnership s income that is effectively connected with the conduct of a United States trade or business and which is allocable to foreign partners. Under rules applicable to publicly traded partnerships, we will withhold at the highest applicable effective tax rate on cash distributions made to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 BEN in order to obtain credit for the taxes withheld.

Because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to United States branch profits tax a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in its U.S. net equity, which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a qualified resident. In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the foreign unitholder. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the disposition.

Administrative Matters

Information Returns and Audit Procedures. We furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his or her share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which is generally not reviewed by counsel, we take various accounting and reporting positions, some of which have been mentioned earlier, to determine the unitholder s share of income, gain, loss and deduction. We cannot assure you that those accounting and reporting positions will yield a result that conforms with the requirements of the Internal Revenue Code, regulations, or administrative interpretations of the IRS. We also cannot assure you that the IRS will not successfully contend in court that those accounting and reporting positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from any such audit may require each unitholder to adjust a prior year s tax liability, and possibly may result in an audit of that unitholder s own return. Any audit of a unitholder s return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code provides for one partner to be designated as the tax matters partner for these purposes. The partnership agreement appoints our general partner as our tax matters partner.

The tax matters partner will make some elections on our behalf and on behalf of unitholders. In addition, the tax matters partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The tax matters partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the tax matters partner. The tax matters partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the tax matters partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits and by unitholders having in the aggregate at least a 5% profits interest. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

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A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of the consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is
  - a person that is not a United States person;
  - a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
  - a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Reportable Transactions. Recently issued Treasury regulations require taxpayers to report certain information on Internal Revenue Service Form 8886 if they participate in a reportable transaction. Unitholders may be required to file this form with the IRS if we participate in a reportable transaction. A transaction may be a reportable transaction based upon any of several factors. Unitholders are urged to consult with their own tax advisor concerning the application of any of these factors to their investment in our common units. Under the recently enacted American Job Creation Act of 2004, significant penalties may be imposed for failure to comply with these requirements. The new law also expanded the responsibilities and potential penalties for promoters of tax shelters. Unitholders are urged to consult with their own tax advisor concerning any possible disclosure obligation with respect to their investment and should be aware that we and our material advisors intend to comply with any applicable disclosure requirements. We do not expect to engage in any reportable transactions.

Accuracy-related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, substantial authority or

- as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

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If any item of income, gain, loss or deduction allocated to unitholders might result in that kind of an understatement of income for which no substantial authority exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty. More stringent rules apply to tax shelters, a term that in this context does not appear to include us.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000. If the valuation claimed on a return is 400% or more than the current valuation, the penalty imposed increases to 40%.

State, Local and Other Tax Considerations

In addition to federal income taxes, you will be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his or her investment in us. We currently own property or do business in Ohio, Oklahoma, Texas, Pennsylvania and New York. Each of these states, except Texas, currently imposes a personal income tax. We may also own property or do business in other states in the future. A unitholder will be required to file state income tax returns and to pay state income taxes in some or all of these states in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder s income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. See Tax Consequences of Ownership Entity-Level Collections. Based on current law and our anticipated future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his or her investment in us. Accordingly, each prospective unitholder should consult, and must depend upon, his or her own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state and local, as well as United States federal tax returns that may be required of him or her. Ledgewood has not rendered an opinion on the state or local tax consequences of an investment in us.

Investment by Employee Benefit Plans

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes the term employee benefit plan includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;

whether, in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA; and

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- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return.

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving plan assets with parties that are parties in interest under ERISA or disqualified persons under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner also would be a fiduciary of the plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed plan assets under some circumstances. Under these regulations, an entity s assets would not be considered to be plan assets if, among other things,

- the equity interests acquired by employee benefit plans are publicly offered securities, i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

- the entity is an operating company, i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

- there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest, disregarding some interests held by our general partner, its affiliates, and some other persons, is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered plan assets under these regulations because we satisfy the first requirement above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

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UNDERWRITING

Lehman Brothers Inc. is acting as sole book-running manager and as the representative of the underwriters. Under the terms of an underwriting agreement, which will be filed as an exhibit to our current report on Form 8-K and incorporated by reference in this prospectus supplement and the accompanying prospectus, each of the underwriters named below has severally agreed to purchase from us the respective number of common units shown opposite its name below:

Underwriters	Number of common units
Lehman Brothers Inc.	756,000
Citigroup Global Markets Inc.	432,000
A.G. Edwards & Sons, Inc.	432,000
Friedman, Billings, Ramsey & Co., Inc.	432,000
Wachovia Capital Markets, LLC	432,000
KeyBanc Capital Markets, a division of McDonald Investments Inc.	135,000
Sanders Morris Harris Inc.	81,000
Total	2,700,000

The underwriting agreement provides that the underwriters obligation to purchase common units depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the common units offered hereby, if any of the common units are purchased;
- the representations and warranties made by us to the underwriters are true;
- there is no material change in the financial markets; and
- we deliver customary closing documents to the underwriters.

Commission and Expenses

The following table summarizes the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional common units. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the common units.

	No exercise	Full exercise
Per unit	$ 1.89	$ 1.89
Total	$ 5,103,000	$ 5,868,450

We have been advised by the underwriters that they propose to offer the common units directly to the public at the public offering price on the cover of this prospectus supplement and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $1.134 per unit. After the offering, the underwriters may change the offering price and other selling terms.

The expenses of the offering that are payable by us are estimated to be $600,000 (exclusive of underwriting discounts and commissions).

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Option to Purchase Additional Common Units

We have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement to purchase, from time to time, in whole or in part, up to an aggregate of 405,000 additional common units at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than 2,700,000 common units in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional common units based on the underwriter s percentage underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting section.

Lock-Up Agreements

We and all of the members of the managing board and executive officers of our general partner have agreed that, without the prior written consent of Lehman Brothers Inc., we and they will not, directly or indirectly, offer, pledge, announce the intention to sell, sell, contract to sell, sell an option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, or otherwise transfer or dispose of any common units or any securities that may be converted into or exchanged for any common units, enter into any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of the common units, make any demand for or exercise any right or file or cause to be filed a registration statement with respect to the registration of any common units or securities convertible, exercisable or exchangeable into common units or any of our other securities or publicly disclose the intention to do any of the foregoing for a period of 90 days from the date of this prospectus supplement other than permitted transfers.

Lehman Brothers Inc., in its sole discretion, may release the common units and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common units and other securities from lock-up agreements, Lehman Brothers Inc. will consider, among other factors, the holder s reasons for requesting the release, the number of common units and other securities for which the release is being requested and market conditions at the time.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

Stabilization, Short Positions and Penalty Bids

The underwriters may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common units, in accordance with Regulation M under the Securities Exchange Act of 1934:

Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

A short position involves a sale by the underwriters of common units in excess of the number of common units the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of common units involved in the sales made by the underwriters in excess of the number of common units they are obligated to purchase is not greater than the number of common units that they may purchase by exercising their option to purchase additional common units. In a naked short position, the number of common units involved is greater than the number of common units in their option to purchase additional common units. The underwriters may close out any short position by either exercising their option to purchase additional common units and/or purchasing common units in the open market. In determining the source of common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through their option to purchase additional common units. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time. Prior to purchasing the common units being offered pursuant to this prospectus supplement, one of the underwriters purchased, on behalf of the syndicate, 88,300 common units at an average price of $42.33975 per unit in stabilizing transactions.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In addition, neither we nor any of the underwriters make any representation that the underwriters will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of common units for sale to online brokerage account holders. Any such allocation for online distributions will be made by the underwriters on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter s or selling group member s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus supplement and the accompanying prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

Stamp Taxes

If you purchase common units offered in this prospectus supplement and the accompanying prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus supplement and the accompanying prospectus.

Relationships

Certain of the underwriters and their related entities have engaged and may engage in commercial and investment banking transactions with Atlas America, our general partner and us in the ordinary course of their business. They have received customary compensation and expenses for these commercial and investment banking transactions. Lehman Brothers Inc. acted as the exclusive financial advisor to Energy Spectrum Capital

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Partners, which held a controlling interest in Spectrum, in the solicitation of proposals for a potential sale transaction of Spectrum. In addition, Lehman Brothers Inc. acted as the exclusive financial advisor to OGE Energy Corporation in the solicitation of proposals for a potential sale transaction of Enogex Arkansas Pipeline Corporation, which became Atlas Arkansas. Friedman, Billings, Ramsey & Co., Inc. and KeyBanc Capital Markets, a division of McDonald Investments Inc., acted as the managing underwriters of our initial public offering and our follow-on offerings in May 2003 and April 2004, and, along with Lehman Brothers Inc., A.G. Edwards & Sons, Inc. and Sanders Morris Harris Inc., our follow-on offering in July 2004, and, along with A.G. Edwards & Sons, Inc., Sanders Morris Harris Inc. and Wachovia Capital Markets, LLC, our follow-on offering in May 2005. Affiliates of Citigroup Global Markets Inc., Wachovia Capital Markets, LLC and KeyBanc Capital Markets, LLC are lenders under our revolving credit facility, holding an aggregate of 19.75% of the commitments under the facility. Because we intend to use more than 10% of the net proceeds from this offering to reduce indebtedness owed by us to affiliates of these underwriters, this offering is being made in compliance with Rule 2710(h) of the National Association of Securities Dealers, Inc. s Conduct Rules.

Discretionary Sales

The underwriters have informed us that they will not confirm sales to discretionary accounts without the prior written approval of the customer.

NASD Conduct Rules

Because the NASD views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD Conduct Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

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LEGAL MATTERS

The validity of the common units and tax matters will be passed upon for us by Ledgewood, Philadelphia, Pennsylvania. Specific legal matters in connection with the offering of the common units are being passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

Our consolidated financial statements as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004; the consolidated balance sheet of Atlas Pipeline Partners GP, LLC as of December 31, 2004; the financial statements of ETC Oklahoma Pipeline, Ltd. as of August 31, 2004 and 2003 and for the year ended August 31, 2004 and for the eleven month period ended August 31, 2003; and the financial statements of the Elk City System (a division of Aquila Gas Pipeline Corporation) for the year ended September 30, 2002 have been audited by Grant Thornton LLP, independent registered public accountants, as indicated in their reports with respect thereto, and are incorporated by reference herein in reliance upon the authority of such firm as experts in giving such reports.

The consolidated financial statements of Enogex Arkansas Pipeline Corporation at December 31, 2004 and 2003, and for each of the two years in the period ended December 31, 2004, appearing in our Current Report on Form 8-K, have been audited by Ernst & Young LLP, independent auditors, as set forth in their report thereon, included therein, and incorporated herein by reference. Such consolidated financial statements are incorporated herein by reference in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-3 with respect to this offering. This prospectus supplement and the accompanying prospectus constitute only part of the registration statement and do not contain all of the information set forth in the registration statement, its exhibits and its schedules.

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC s web site at http://www.sec.gov. You may also read and copy any document we file at the SEC s public reference rooms. Please call the SEC at 1-800-SEC-0330 for additional information on the public reference rooms.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The SEC allows us to incorporate by reference the information we file with it. This means that we can disclose important information to you by referring to these documents. The information incorporated by reference is an important part of this prospectus supplement and the accompanying prospectus, and information that we file later with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 will automatically update and supersede this information.

We are incorporating by reference the following documents that we have previously filed with the SEC (other than information in such documents that is deemed not to be filed):

our Annual Report on Form 10-K for the fiscal year ended December 31, 2004;

our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2005, June 30, 2005 and September 30, 2005; and

our Current Reports on Form 8-K filed March 14, 2005, March 22, 2005, April 18, 2005, May 13, 2005, May 24, 2005, May 27, 2005, September 22, 2005, October 31, 2005, November 4, 2005 and November 18, 2005.

You may obtain a copy of these filings without charge by writing or calling us at:

Investor Relations

Atlas Pipeline Partners, L.P.

311 Rouser Road

P.O. Box 611

Moon Township, Pennsylvania 15108

(412) 262-2830

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$500,000,000

ATLAS PIPELINE PARTNERS, L.P.

Common Units

Subordinated Units

Debt Securities

Warrants

We may offer from time to time the following types of securities:

- our common units representing limited partner interests;
- our subordinated units representing limited partner interests;
- our debt securities, in one or more series, which may be senior debt securities or subordinated debt securities, in each case consisting of notes or other evidences of indebtedness;
- warrants to purchase any of the other securities that may be sold under this prospectus; or
- any combination of these securities, individually or as units.

The securities will have an aggregate initial offering price of up to $500,000,000. The securities may be offered separately or together in any combination and as a separate series. This prospectus also covers guarantees, if any, of our payment obligations under any debt securities, which may be given by certain of our subsidiaries on terms to be determined at the time of the offering.

We will provide specific terms of these securities in supplements to this prospectus. You should read this prospectus and any prospectus supplement, as well as the documents incorporated or deemed to be incorporated by reference in this prospectus, carefully before you invest. This prospectus may not be used to consummate sales of securities unless accompanied by the applicable prospectus supplement.

Our common units are quoted on the New York Stock Exchange under the symbol APL. Our principal executive offices are located at 311 Rouser Road, Moon Township, PA 15108. Our telephone number is (412) 262-2830.

You should read Risk Factors beginning on page 1 of this prospectus, as well as those which may be contained in any supplement to this prospectus, for a discussion of important factors that you should consider before you invest.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

We may sell these securities directly, through agents, dealers or underwriters as designated from time to time, or through a combination of these methods. We reserve the sole right to accept, and together with our agents, dealers and underwriters reserve the right to reject, in whole or in part, any proposed purchase of securities to be made directly or through agents, dealers or underwriters. If any agents, dealers or underwriters are involved in the sale of any securities, the relevant prospectus supplement will set forth any applicable commissions or discounts. Our net proceeds from the sale of securities also will be set forth in the relevant prospectus supplement.

Prospectus dated August 30, 2005

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About this Prospectus

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission using a shelf registration process. Under this process, over the period ending August 30, 2007, we may, from time to time, offer any combination of the securities described in this prospectus in one or more offerings up to a total dollar amount of $500,000,000. This prospectus provides you with a general description of the securities we may offer. Each time we use this prospectus to offer these securities, we will provide a prospectus supplement that will contain specific information about the terms of that offering. The prospectus supplement may also add, update or change information contained in this prospectus. Please carefully read this prospectus and the prospectus supplement together with the additional information described under the heading Where You Can Find More Information.

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RISK FACTORS

You should consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our securities. 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 you may lose some or all of your investment.

Our revenues depend in part on factors beyond our control.

Our revenues 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, treat or process;
- continued development of wells for connection to our gathering systems;
- the availability of local, intrastate and interstate transportation systems;
- the expenses we incur in providing our gathering services;
- the cost of acquisitions and capital improvements;
- our issuance of equity securities;
- required principal and interest payments on our debt;
- fluctuations in working capital;
- prevailing economic conditions;
- fuel conservation measures;
- alternate fuel requirements;

government regulation and taxation; and

technical advances in fuel economy and energy generation devices.

Our profitability is affected by the volatility of prices for natural gas and NGL products.

We derive a substantial portion of our revenues from percentage of proceeds contracts. As a result, our income depends to a significant extent upon the prices at which the natural gas we transport, treat or process and the natural gas liquids, or NGLs, we produce are sold. A 10% increase in the average price of NGLs, natural gas and crude oil we process and sell would result in an increase to our 2005 annual income of approximately $2.5 million. A 10% decrease in the average price of NGLs, natural gas and crude oil we process and sell would result in a decrease to our 2005 annual income of approximately $2.3 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations and thus the volume of gas we gather and process. Historically, the price of both natural gas and NGLs has been subject to significant volatility in response to relatively minor changes in the supply and demand for natural gas and NGL products, market uncertainty and a variety of additional factors beyond our control, including those we describe in Our revenues depend in part on factors beyond our control, above. We expect this volatility to continue. For example, during the year ended December 31, 2004, the NYMEX settlement price for the prompt month contract ranged from a high of $7.98 per MMbtu to a low of $5.08 per MMbtu. A composite of the monthly Mont Belvieu average NGLs price based upon our average NGLs composition during the year ended December 31, 2004, ranged from a high of $0.80 per gallon to a low of $0.53 per gallon. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the throughput volumes subject to percentage of proceeds contracts. Moreover, hedges are subject to inherent risks, which we describe in Our hedging strategies may fail to protect us and could reduce our gross margin and cash flow.

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The amount of natural gas we transport, treat or process will decline over time unless we are able to attract new wells to connect to our gathering systems.

Production of natural gas from a well generally declines over time until the well can no longer economically produce natural gas and is plugged and abandoned. Failure to connect new wells to our gathering systems could, therefore, result in the amount of natural gas we transport, treat or process reducing substantially over time and could, upon exhaustion of the current wells, cause us to abandon one or more of our gathering systems and, possibly, cease operations. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing wells that are not committed to other systems, the level of drilling activity near our gathering systems and, in the Mid-Continent region, our ability to attract natural gas producers away from our competitors gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over the level of drilling activity in our service areas, the amount of reserves underlying wells that connect to our systems and the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. Because our operating costs are fixed to a significant degree, a reduction in the natural gas volumes we transport, treat or process would result in a reduction in our gross margin and cash flows.

The success of our Appalachian operations depends upon Atlas America, Inc. s ability to drill and complete commercial producing wells.

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

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

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

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

Unlike our Appalachian operations, none of the drillers or operators in our Mid-Continent service area is an affiliate of ours. Moreover, our agreements with most of the drillers and operators with which our Mid-Continent

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operations do business do not require them to dedicate significant amounts of undeveloped acreage to our systems. As a result, we do not have assured sources to provide us with new wells to connect to our Mid-Continent gathering systems. Failure to connect new wells to our Mid-Continent operations will, as described in The amount of natural gas we transport, treat or process will decline over time unless we are able to attract new wells to connect to our gathering systems, above, reduce our gross margin and cash flows.

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

During 2004, Mack Energy Corporation, Zinke & Trumbo, Inc., Chevron Corporation and Chesapeake Energy Corporation supplied our Velma system with approximately 60% of its natural gas supply. During that same period, Chesapeake, Kaiser-Francis Oil Company, Burlington Resources Inc. and St. Mary Land and Exploration Company supplied our Elk City system with approximately 74% of its natural gas supply. If these producers reduce the volumes of natural gas that they supply to us, our gross margin and cash flows would be reduced unless we obtain comparable supplies of natural gas from other producers.

The curtailment of operations at, or closure of, either of our processing plants or treating plant could harm our business.

We have one processing plant for our Elk City operation and one active processing plant for our Velma operation. If operations at either plant were to be curtailed, or closed, whether due to accident, natural catastrophe, environmental regulation or for any other reason, our ability to process natural gas from the relevant gathering system and, as a result, our ability to extract and sell NGLs, would be harmed. If this curtailment or stoppage were to extend for more than a short period, our gross margin and cash flows would be materially reduced.

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

Our Mid-Continent operations may face competition for well connections. Duke Energy Field Services, LLC, ONEOK, Inc., Carrera Gas Company, Cimmarron Transportation, LLC and Enogex, Inc. operate competing gathering systems and processing plants in our Velma service area. In our Elk City service area, ONEOK, Enbridge Energy Partners, L.P., CenterPoint Energy, Inc. and Enogex operate competing gathering systems and processing plants. Some of our competitors have greater financial and other resources than we do. If these companies become more active in our Mid-Continent service areas, we may not be able to compete successfully with them in securing new well connections or retaining current well connections. If we do not compete successfully, the amount of natural gas we transport, process and treat will decrease, reducing our gross margin and cash flows.

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

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

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

Our Mid-Continent gathering systems are located in Oklahoma and northern Texas, areas in which we have been involved only since July 2004 as a result of the Velma acquisition and, in April 2005, the Elk City acquisition. In addition, as a result of these acquisitions, we began to operate natural gas processing plants, a business in which we had no prior operating experience. We depend upon the experience, knowledge and business relationships that have been developed by the senior management of our Mid-Continent operations to operate successfully in the region. The loss of the services of one or more members of our Mid-Continent senior management and, in particular, Robert R. Firth, President, and David D. Hall, Chief Financial Officer, could limit our growth or our ability to maintain our current level of operations in the Mid-Continent region.

Acquisition of our Velma and Elk City operations has substantially changed our business, making it difficult to evaluate our business based upon our historical financial information.

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

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

Our strategy contemplates substantial growth through both the acquisition of other gathering systems and processing assets and the expansion of our existing gathering systems and processing assets. Our growth strategy involves numerous risks, including:

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

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

We have an active, on-going program to identify other potential acquisitions. The integration of previously independent operations with ours can be a complex, costly and time-consuming process. The difficulties of combining any operations we may acquire in the future with us include, among other things:

- the necessity of coordinating geographically disparate organizations, systems and facilities;
- integrating personnel with diverse business backgrounds and organizational cultures;
- consolidating operational and administrative functions;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management s attention from other business concerns;

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- customer or key employee loss from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

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

Limitations on our access to capital or on the market for our common units will impair our ability to execute our growth strategy.

Our ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, we have financed our acquisitions, and to a much lesser extent, expansions of our gathering systems by bank credit facilities and the proceeds of public and private equity offerings of our common units and preferred units of our operating partnership. If we are unable to access the capital markets, we may be unable to execute our strategy of growth through acquisitions.

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

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

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

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

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

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

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

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

Our operations are subject to all operating hazards and risks incidental to transporting and processing natural gas and NGLs. These hazards include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods and other natural disasters;

- inadvertent damage from construction and farm equipment;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions;
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations; and
- acts of terrorism directed at our pipeline infrastructure, production facilities, transmission and distribution facilities and surrounding properties.

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

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, or interpretations of existing laws, 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 gross margin and cash flows, 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. Similarly, the Texas Railroad Commission sponsors a complaint procedure for resolving grievances about natural gas gathering access and rate discrimination. The gathering fees we charge 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 change in status under these regulations that subjects us to further regulation, could increase our operating costs or require material capital expenditures.

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USE OF PROCEEDS

Unless we indicate otherwise in an accompanying prospectus supplement, we intend to use the net proceeds from the sale of the securities offered by this prospectus for general partnership purposes, which may include, but not be limited to, refinancing of indebtedness, working capital, capital expenditures, acquisitions and repurchases and redemptions of securities.

RATIO OF EARNINGS TO FIXED CHARGES

The following table shows our ratio of earnings to fixed charges for the periods indicated.

	Six months ended June 30,	Year ended December 31,				Inception through December 31,
	2005	2004	2003	2002	2001	2000
Ratio of earnings to fixed charges	2.4	8.1	29.3	18.0	36.8	737.1

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CONFLICTS OF INTEREST AND FIDUCIARY RESPONSIBILITIES

Conflicts of Interest

General

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and Atlas America and its affiliates, on the one hand, and us and our limited partners, on the other hand. The managing board members and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to Atlas America and its affiliates as members. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders.

Our partnership agreement contains provisions that allow our general partner to take into account the interests of parties in addition to ours in resolving conflicts of interest. In effect, these provisions limit our general partner s fiduciary duty to the unitholders. The partnership agreement also restricts the remedies available to unitholders for actions taken that might, without those limitations, constitute breaches of fiduciary duty.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any partner, on the other, our general partner has the responsibility to resolve that conflict. A conflicts committee of our general partner s managing board will, at the request of our general partner, review conflicts of interest. The conflicts committee consists of the independent managing board members, currently Messrs. Curtis Clifford and Martin Rudolph and Dr. Gayle P. W. Jackson. Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is considered to be fair and reasonable to us. Any resolution is considered to be fair and reasonable to us if that resolution is:

- approved by the conflicts committee, although no party is obligated to seek approval and our general partner may adopt a resolution or course of action that has not received approval;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In resolving a conflict, our general partner may, unless the resolution is specifically provided for in the partnership agreement, consider:

- the relative interest of the parties involved in the conflict or affected by the action;
- any customary or accepted industry practices or historical dealings with a particular person or entity; and

generally accepted accounting practices or principles and other factors as it considers relevant, if applicable.

Conflicts of interest could arise in the situations described below, among others:

We do not have any employees and rely on the employees of our general partner and its affiliates.

We do not have any officers or employees and rely solely on officers and employees of our general partner and its affiliates. Affiliates of our general partner conduct business and activities of their own in which we 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.

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We must reimburse our general partner and its affiliates for expenses.

We must reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services properly allocable to us.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only as to all or particular assets of ours and not against our general partner or its assets. Our partnership agreement provides that any action taken by our general partner to limit our or its liability is not a breach of our general partner s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Determinations by our general partner may affect its obligations and the obligations of Atlas America.

We have agreements with Atlas America regarding, among other things, transporting natural gas from wells controlled by it and its affiliates, construction of expansions to our gathering systems and identification of other gathering systems for acquisition. Determinations made by our general partner will significantly affect the obligations of Atlas America under these agreements. For example, a determination not to acquire a gathering system identified by Atlas America could result in the acquisition of that system by Atlas America.

Contracts between us, on the one hand, and our general partner and Atlas America and its affiliates, on the other, will not be the result of arm s-length negotiations.

Our partnership agreement allows our general partner to pay itself or its affiliates for any services rendered, provided these services are on terms fair and reasonable to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its affiliates on the other, are or will be the result of arm s length negotiations.

We may not retain separate counsel or other professionals.

Attorneys, independent public accountants and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and Atlas America and its affiliates. We may retain separate counsel in the event of a conflict of interest arising between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of that conflict. We do not intend to do so in most cases.

Fiduciary Duties

State Law Fiduciary Duty Standards

Fiduciary duties are generally considered to include an obligation to act with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.

The Delaware Revised Uniform Limited Partnership Act provides that a limited partner may institute legal action on our behalf to recover damages from a third party where our general partner has refused to institute the action or where an effort to cause our general partner to do so is not likely to succeed. In addition, the statutory or case law may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

Partnership Agreement Modified Standards; Limitations on Remedies of Unitholders

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, the partnership agreement permits our general partner to make a number of decisions in its sole discretion. This entitles our general partner to consider only the interests and factors that it desires; it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Other provisions of the partnership agreement provide that our general partner s actions must be made in its reasonable discretion. These standards reduce the obligations to which our general partner would otherwise be held and limit the remedies that would otherwise be available to unitholders for actions by our general partner that, in the absence of those standards, might constitute breaches of fiduciary duty to unitholders.

Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be fair and reasonable to us under the factors previously described. In determining whether a transaction or resolution is fair and reasonable, our general partner may consider interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner will not constitute a breach of its fiduciary duty. These standards reduce the obligations to which our general partner would otherwise be held and limit the remedies that would otherwise be available to unitholders for actions by our general partner that, in the absence of those standards, might constitute breaches of fiduciary duty to unitholders.

Our partnership agreement specifically provides that, subject only to the obligations of Atlas America and its affiliates to us under the omnibus agreement, the master natural gas gathering agreement or similar agreements, it will not be a breach of our general partner s fiduciary duty if its affiliates engage in business interests and activities in preference to or to the exclusion of us. Also, our general partner and its affiliates have no obligation to present business opportunities to us except for the obligation of Atlas America to us in connection with the identification of potential acquisitions of existing gathering systems. These standards reduce the obligations to which our general partner would otherwise be held and limit the remedies that would otherwise be available to unitholders for actions by our general partner that, in the absence of those standards, might constitute breaches of fiduciary duty to unitholders.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and managing board members will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

In order to become a limited partner, a unitholder is required to agree to be bound by the provisions of our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Revised Uniform Limited Partnership Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We are required to indemnify our general partner and its officers, managing board members, employees, affiliates, partners, members, agents and trustees, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. This indemnification is required if our general partner or the other persons acted in good faith and in a manner they reasonably believed to be in, or not opposed to, our best interests. Indemnification is required for criminal proceedings if our general partner or these other persons had no reasonable cause to believe their conduct was unlawful. See Our Partnership Agreement Indemnification.

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GENERAL DESCRIPTION OF SECURITIES THAT WE MAY SELL

We, directly or through agents, dealers or underwriters that we may designate, may offer and sell, from time to time, up to $500,000,000 aggregate initial offering price of:

- our common units representing limited partner interests;
- our subordinated units representing limited partner interests;
- our debt securities, in one or more series, which may be senior debt securities or subordinated debt securities, in each case consisting of notes or other evidences of indebtedness;
- warrants to purchase any of the other securities that may be sold under this prospectus; or
- any combination of these securities, individually or as units.

We may offer and sell these securities either individually or as units consisting of one or more of these securities, each on terms to be determined at the time of sale. We may issue debt securities that are exchangeable for and/or convertible into common units or any of the other securities that may be sold under this prospectus. When particular securities are offered, a supplement to this prospectus will be delivered with this prospectus, which will describe the terms of the offering and sale of the offered securities.

DESCRIPTION OF COMMON UNITS

We describe our common units under the heading Our Partnership Agreement. The prospectus supplement relating to the common units offered will state the number of units offered, the initial offering price and the market price, distribution information and any other relevant information.

DESCRIPTION OF SUBORDINATED UNITS

The subordinated units will be a separate class of limited partner interest. The rights of holders of subordinated units to participate in distributions to partners will differ from, and be subordinated to, the rights of the holders of common units. The prospectus supplement relating to the subordinated units offered will state the number of units offered, the initial offering price and the market price, the terms of the subordination, any ways in which the subordinated units will differ from common units, distribution information and any other relevant information.

DESCRIPTION OF DEBT SECURITIES

We may issue debt securities either separately, or together with, or upon the conversion of or in exchange for, other securities. The debt securities may be our unsubordinated obligations, which we refer to as senior debt securities, or our subordinated obligations, which we refer to as subordinated debt securities. The subordinated debt securities of any series may be our senior subordinated obligations, subordinated obligations, junior subordinated obligations or may have such other ranking as will be described in the relevant prospectus supplement. We may issue any of these types of debt securities in one or more series.

Our senior debt securities may be issued from time to time under a senior debt securities indenture. Our subordinated debt securities may be issued from time to time under a subordinated debt securities indenture. Each of the senior debt securities indenture and the subordinated debt securities indenture is referred to individually as an indenture and they are referred to collectively as the indentures. Each trustee is referred to individually as a trustee and the trustees are collectively referred to as the trustees.

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This section summarizes selected terms of the debt securities that we may offer. The applicable prospectus supplement and the form of applicable indenture relating to any particular debt securities offered will describe the specific terms of that series, which may be in addition to or different from the general terms summarized in this section. If any particular terms of the debt securities described in a prospectus supplement differ from any of the terms described in this prospectus, then the terms described in the applicable prospectus supplement will supersede the terms described in this prospectus. The following summary and any description of our debt securities contained in an applicable prospectus supplement do not describe every aspect of the applicable indenture or the debt securities. When evaluating the debt securities, you also should refer to all provisions of the applicable indenture and the debt securities. The forms of indentures have been filed as exhibits to the registration statement of which this prospectus is a part.

General

We can issue an unlimited amount of debt securities under the indentures. However, certain of our existing or future debt agreements may limit the amount of debt securities we may issue. We can issue debt securities from time to time and in one or more series as determined by us. In addition, we can issue debt securities of any series with terms different from the terms of debt securities of any other series and the terms of particular debt securities within any series may differ from each other, all without the consent of the holders of previously issued series of debt securities.

The applicable prospectus supplement relating to the series of debt securities will describe the specific terms of the debt securities being offered, including, where applicable, the following:

- the title and series designation of the series of debt securities and whether the debt securities of the series will be senior debt securities or subordinated debt securities;
- any limit on the aggregate principal amount of debt securities of the series;
- the price or prices at which the debt securities of the series will be issued;
- whether the debt securities of the series will be guaranteed and the terms of any such guarantees;
- the date or dates on which the principal amount and premium, if any, are payable;
- the interest rate or rates or the method for calculating the interest rate, which may be fixed or variable, at which the debt securities of the series will bear interest, if any, the date or dates from which interest will accrue and the interest payment date on which interest will be payable, subject to our right, if any, to defer or extend an interest payment date and the duration of that deferral or extension;
- the date or dates on which interest, if any, will be payable and the record dates for payment of interest;
- the place or places where the principal and premium, if any, and interest, if any, will be payable and where the debt securities of the series can be surrendered for transfer, conversion or exchange;

our right, if any, to redeem the debt securities and the terms and conditions upon which the debt securities of the series may be redeemed, in whole or in part;

any mandatory or optional sinking fund or analogous provisions;

if the debt securities of the series will be secured, any provisions relating to the security provided;

whether the debt securities of the series are convertible or exchangeable into other debt or equity securities, and, if so, the terms and conditions upon which such conversion or exchange will be effected;

whether any portion of the principal amount of the debt securities of the series will be payable upon declaration or acceleration of the maturity thereof pursuant to an event of default;

whether the debt securities of the series, in whole or any specified part, will not be defeasible pursuant to the applicable indenture and, if other than by an officers certificate, the manner in which any election by us to defease the debt securities of the series will be evidenced;

any deletions from, modifications of or additions to the events of default or our covenants pertaining to the debt securities of the series;

any terms applicable to debt securities of any series issued at an issue price below their stated principal amount, including the issue price thereof and the rate or rates at which the original issue discount will accrue;

whether the debt securities of the series are to be issued or delivered (whether at the time of original issuance or at the time of exchange of a temporary security of such series or otherwise), or any installment of principal or any premium or interest is to be payable only, upon receipt of certificates or other documents or satisfaction of other conditions in addition to those specified in the applicable indenture;

whether the debt securities of the series are to be issued in fully registered form without coupons or are to be issued in the form of one or more global securities in temporary global form or permanent global form;

whether the debt securities of the series are to be issued in registered or bearer form, the terms and conditions relating the applicable form, including, but not limited to, tax compliance, registration and transfer procedures and, if in registered form, the denominations in which we will issue the registered securities if other than $1,000 or a multiple thereof and, if in bearer form, the denominations in which we will issue the bearer securities;

any special United States federal income tax considerations applicable to the debt securities of the series;

any addition to or change in the covenants set forth in the indenture which apply to the debt securities of the series; and

any other terms of the debt securities of the series not inconsistent with the provisions of the applicable indenture.

The prospectus supplement relating to any series of subordinated debt securities being offered also will describe the subordination provisions applicable to that series, if different from the subordination provisions described in this prospectus. In addition, the prospectus supplement relating to a series of subordinated debt will describe our rights, if any, to defer payments of interest on the subordinated debt securities by extending the interest payment period.

Debt securities may be issued as original issue discount securities to be sold at a discount below their principal amount or at a premium above their principal amount. In the event of an acceleration of the maturity of any original issue discount security, the amount payable to the holder upon acceleration will be determined in the manner described in the applicable prospectus supplement.

The above is not intended to be an exclusive list of the terms that may be applicable to any debt securities and we are not limited in any respect in our ability to issue debt securities with terms different from or in addition to those described above or elsewhere in this prospectus, provided that the terms are not inconsistent with the applicable indenture. Any applicable prospectus supplement also will describe any special provisions for the payment of additional amounts with respect to the debt securities.

Guarantees

Debt securities may be guaranteed by certain of our subsidiaries, if so provided in the applicable prospectus supplement. The prospectus supplement will describe the terms of any guarantees, including, among other things, the method for determining the identity of the guarantors and the conditions under which guarantees will be added or released. Any guarantees will be joint and several obligations of the guarantors. The obligations of each guarantor under its guarantee will be limited as necessary to prevent that guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable law.

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Subordination Provisions Relating to Subordinated Debt

Debt securities may be subject to contractual subordination provisions contained in the subordinated debt securities indenture. These subordination provisions may prohibit us from making payments on the subordinated debt securities in certain circumstances before a defined class of senior indebtedness is paid in full or during certain periods when a payment or other default exists with respect to certain senior indebtedness. If we issue subordinated debt securities, the applicable prospectus supplement relating to the subordinated debt securities will include a description of the subordination provisions and the definition of senior indebtedness that apply to the subordinated debt securities.

If the trustee under the subordinated debt indenture or any holder of the series of subordinated debt securities receives any payment or distribution that is prohibited under the subordination provisions, then the trustee or the holders will have to repay that money to the holders of senior indebtedness.

Even if the subordination provisions prevent us from making any payment when due on the subordinated debt securities of any series, we will be in default on our obligations under that series if we do not make the payment when due. This means that the trustee under the subordinated debt indenture and the holders of that series can take action against us, but they will not receive any money until the claims of the holders of senior indebtedness have been fully satisfied.

Unless otherwise indicated in an applicable prospectus, if any series of subordinated debt securities is guaranteed by certain of our subsidiaries, then the guarantee will be subordinated to the senior indebtedness of such guarantor to the same extent as the subordinated debt securities are subordinated to the senior indebtedness.

Conversion and Exchange Rights

The debt securities of a series may be convertible into or exchangeable for any of our other securities, if at all, according to the terms and conditions of an applicable prospectus supplement. Such terms will include the conversion or exchange price and any adjustments thereto, the conversion or exchange period, provisions as to whether conversion or exchange will be mandatory, at our option or at the option of the holders of that series of debt securities and provisions affecting conversion or exchange in the event of the redemption of that series of debt securities.

Form, Exchange, Registration and Transfer

The debt securities of a series may be issued as registered securities, as bearer securities (with or without coupons attached) or as both registered securities and bearer securities. Debt securities of a series may be issuable in whole or in part in the form of one or more global debt securities, as described below under Global Debt Securities. Unless otherwise indicated in an applicable prospectus supplement, registered securities will be issuable in denominations of $1,000 and integral multiples thereof.

Registered securities of any series will be exchangeable for other registered securities of the same series of any authorized denominations and of a like aggregate principal amount and tenor. Debt securities may be presented for exchange as provided above, and unless otherwise indicated in an applicable prospectus supplement, registered securities may be presented for registration of transfer, at the office or agency designated by us as registrar or co-registrar with respect to any series of debt securities, without service charge and upon payment of any taxes, assessments or other governmental charges as described in the applicable indenture. The transfer or exchange will be effected on the books of the registrar or any other transfer agent appointed by us upon the registrar or transfer agent, as the case may be, being satisfied with the documents of title and identity of the person making the request. We intend to initially appoint the trustee as registrar and the name of any different or additional registrar designated by us with respect to the debt securities of any series will be included in the applicable prospectus supplement. If a prospectus supplement refers to any transfer agents (in addition to the registrar) designated by us with respect to any series of debt securities, we may at any time rescind the designation of any transfer agent or approve a change in the location through which any transfer agent acts, except that, if debt securities of a series are issuable only as registered securities, we will be required to maintain a transfer agent in each place of payment for that series. We may at any time designate additional transfer agents with respect to any series of debt securities.

In the event of any redemption of debt securities of any series, we will not be required to:

- issue, register the transfer of or exchange debt securities of that series during a period beginning at the opening of business 15 days before any selection of debt securities of that series to be redeemed and ending at the close of business on the day of mailing of the relevant notice of redemption; or

- register the transfer of or exchange any registered security, or portion thereof, called for redemption, except the unredeemed portion of any registered security being redeemed in part.

Payment and Paying Agents

Unless otherwise indicated in an applicable prospectus supplement, payment of principal of, premium, if any, and interest, if any, on registered securities will be made at the office of the paying agent or paying agents designated by us from time to time, except that at our option, payment of principal and premium, if any, or interest also may be made by wire transfer to an account maintained by the payee. Unless otherwise indicated in an applicable prospectus supplement, payment of any installment of interest on registered securities will be made to the person in whose name the registered security is registered at the close of business on the regular record date for the interest payment.

Unless otherwise indicated in an applicable prospectus supplement, the trustee will be designated as our sole paying agent for payments with respect to debt securities which are issuable solely as registered securities. We may at any time designate additional paying agents or rescind the designation of any paying agent or approve a change in the office through which any paying agent acts, except that, if debt securities of a series are issuable only as registered securities, we will be required to maintain a paying agent in each place of payment for that series.

All monies paid by us to a paying agent for the payment of principal of, premium, if any, or interest, if any, on any debt security which remains unclaimed at the end of two years after that principal or interest will have become due and payable will be repaid to us, and the holder of the debt security or any coupon will thereafter look only to us for payment of those amounts.

Global Debt Securities

The debt securities of a series may be issued in whole or in part in global form. A global debt security will be deposited with, or on behalf of, a depositary, which will be identified in an applicable prospectus supplement. A global debt security may be issued in either registered or bearer form and in either temporary or permanent form. A global debt security may not be transferred except as a whole to the depositary for the debt security or to a nominee or successor of the depositary. If any debt securities of a series are issuable in global form, the applicable prospectus supplement will describe the circumstances, if any, under which beneficial owners of interests in a global debt security may exchange their interests for definitive debt securities of that series of like tenor and principal amount in any authorized form and denomination, the manner of payment of principal of, premium, if any, and interest, if any, on the global debt securities and the specific terms of the depositary arrangement with respect to any global debt security.

Covenants

Reports. Except as otherwise set forth in an applicable prospectus supplement, so long as any debt securities of a series are outstanding, we will furnish to the holders of debt securities of that series, within the time periods specified in the rules and regulations of the SEC:

- our reports on Forms 10-Q and 10-K, including a Management s Discussion and Analysis of Financial Condition and Results of Operations and, with respect to the annual information only, a report on the audited financial statements by our certified independent accountants; and

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all current reports on Form 8-K.

We also will file a copy of all of the foregoing information and reports with the SEC for public availability within the time periods specified in the SEC s rules and regulations (unless the SEC will not accept such a filing) and make such information available to securities analysts and prospective investors upon request.

Any additional covenants with respect to any series of debt securities will be set forth in the applicable prospectus supplement. Unless otherwise indicated in an applicable prospectus supplement, the indentures do not include covenants restricting our ability to enter into a highly leveraged transaction, including a reorganization, restructuring, merger or similar transaction involving us that may adversely affect the holders of the debt securities, if the transaction is a permissible consolidation, merger or similar transaction. In addition, unless otherwise specified in an applicable prospectus supplement, the indentures do not afford the holders of the debt securities the right to require us to repurchase or redeem the debt securities in the event of a highly leveraged transaction. See Merger, Consolidation and Sale of Assets.

Merger, Consolidation and Sale of Assets

Except as otherwise set forth in an applicable prospectus supplement, we may not, directly or indirectly:

consolidate with or merge into any other person (whether or not we are the surviving corporation); or

sell, assign, transfer, convey or otherwise dispose of all or substantially all of our properties and assets, unless

either

we are the continuing corporation; or

the person formed by or surviving any such consolidation or merger (if other than us) or to which such sale, assignment, transfer, conveyance or disposition will have been made is a corporation organized and existing under the laws of the United States, any state thereof or the District of Columbia and that person assumes all of our obligations under the debt securities of such series and the indenture relating thereto pursuant to agreements reasonably satisfactory to the applicable trustee; and

any other conditions specified in the applicable prospectus supplement have been satisfied.

In addition, we may not, directly or indirectly, lease all or substantially all of our properties or assets in one or more related transactions to any other person. This covenant will not apply to a sale, assignment, transfer, conveyance or other disposition of assets between or among us and any guarantors, if applicable.

Events of Default and Remedies

Under each indenture, unless otherwise specified with respect to a series of debt securities, the following events will constitute an event of default with respect to any series of debt securities:

- default for 30 days in the payment when due of any interest on any debt securities of that series;
- default in payment when due of the principal of, or premium, if any, on any debt security of that series;
- failure to comply with the provisions described under the caption Merger, Consolidation and Sale of Assets ;
- failure for 60 days after notice to comply with any of the other agreements in the indenture;
- except as permitted by the indenture, if debt securities of a series are guaranteed, any guarantee shall be held in any final, non-appealable judicial proceeding to be unenforceable or invalid or shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny, or disaffirm its obligations under its guarantee (unless such guarantor could be released from its guarantee in accordance with the applicable terms of the indenture);

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- certain events of bankruptcy or insolvency described in the indenture with respect to us or any of our significant subsidiaries, as defined below; and

- any other event of default applicable to the series of debt securities and set forth in the applicable prospectus supplement.

For purposes of this section, significant subsidiary means any subsidiary that would be a significant subsidiary as defined in Article 1, Rule 1-02 of Regulation S-X, promulgated pursuant to the Securities Act.

Each indenture provides that in the case of an event of default arising from certain events of bankruptcy or insolvency relating to us with respect to a series of debt securities, all outstanding debt securities of that series will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding debt securities of that series may declare all the debt securities of that series to be due and payable immediately.

Holders of the debt securities of a series may not enforce the indenture or the debt securities of that series except as provided in the indenture. Subject to certain limitations, holders of a majority in principal amount of the then outstanding debt securities of a series may direct the trustee in its exercise of any trust or power. The trustee may withhold from holders of the debt securities of a series notice of any continuing default or event of default if it determines that withholding notice is in their interest, except a default or event of default relating to the payment of principal or interest.

Each indenture provides that we are required to deliver to the trustee annually a statement regarding compliance with the indenture. Upon becoming aware of any default or event of default, we are required to deliver to the trustee a statement specifying such default or event of default.

The holders of a majority in aggregate principal amount of the debt securities of a series then outstanding by notice to the trustee may on behalf of the holders of all of the debt securities of that series waive any existing default or event of default and its consequences under the indenture except a continuing default or event of default in the payment of interest or premium on, or the principal of, the debt securities of that series.

Such limitations do not apply, however, to a suit instituted by a holder of any debt security for the enforcement of the payment of the principal of, premium, if any, and interest in respect of a debt security on the date specified for payment in the debt security. Unless otherwise specified with respect to a series of debt securities, the holders of at least a majority in aggregate principal amount of the then outstanding debt securities of that series may, on behalf of the holders of the debt securities of any series, waive any past defaults under the applicable indenture, other than:

- a default in any payment of the principal of, and premium, if any, or interest on, any debt security of the series; or

- any default in respect of the covenants or provisions in the applicable indenture which may not be modified without the consent of the holder of each outstanding debt security of the series affected.

Amendment, Supplement and Waiver

Each indenture permits us and the applicable trustee, with the consent of the holders of at least a majority in aggregate principal amount of the outstanding debt securities of the series affected by the supplemental indenture, to execute a supplemental indenture to add provisions to, or change in any manner or eliminate any provisions of, the indenture with respect to that series of debt securities or modify in any manner the rights of the holders of the debt securities of that series and any related coupons under the applicable indenture. However, the supplemental indenture will not, without the consent of the holder of each outstanding debt security of that series affected thereby:

- change the stated maturity of the principal of, or any installment of principal or interest on, the debt securities of that series or any premium payable upon redemption thereof;

reduce the principal amount of, or premium, if any, or the rate of interest on, the debt securities of that series;

change the place or currency of payment of principal and premium, if any, or interest, if any, on the debt securities of that series;

impair the right to institute suit for the enforcement of any payment after the stated maturity date on any debt securities of that series, or in the case of redemption, on or after the redemption date;

reduce the principal amount of outstanding debt securities of that series necessary to modify or amend or waive compliance with any provisions of the indenture;

release any applicable guarantor from any of its obligations under its guarantee or the indenture, except in accordance with the indenture;

modify the foregoing amendment and waiver provisions, except to increase the percentage in principal amount of outstanding debt securities of any series necessary for such actions or to provide that certain other provisions of the indenture cannot be modified or waived without the consent of the holder of each debt security of a series affected thereby; and

change such other matters as may be specified in an applicable prospectus supplement for any series of debt securities.

The indentures also permit us, the guarantors, if any, and the applicable trustee to execute a supplemental indenture without the consent of the holders of the debt securities:

to cure any ambiguity, defect or inconsistency;

to provide for uncertificated debt securities in addition to or in place of certificated debt securities;

to provide for the assumption of our obligations or, if applicable, a guarantor s obligations to holders of debt securities of a series in the case of a merger or consolidation or sale of all or substantially all of our assets or, if applicable, a guarantor s assets;

to make any change that would provide any additional rights or benefits to the holders of debt securities of a series or that does not adversely affect the legal rights under the indenture of any such holder;

to comply with the requirements of the SEC in order to effect or maintain the qualification of the indenture under the Trust Indenture Act;

to add a guarantor under the indenture;

to evidence and provide the acceptance of the appointment of a successor trustee under the applicable indenture;

to mortgage, pledge, hypothecate or grant a security interest in favor of the trustee for the benefit of the holders of debt securities of any series as additional security for the payment and performance of our or any applicable guarantor s obligations under the applicable indenture, in any property or assets;

to add to, change or eliminate any provisions of the applicable indenture (which addition, change or elimination may apply to one or more series of debt securities), provided that, any such addition, change or elimination:

shall neither:

apply to any debt security of any series created prior to the execution of such supplemental indenture and entitled to the benefit of such provision nor

modify the rights of the holders of such debt securities with respect to such provisions or

shall become effective only when there is no such outstanding debt securities of such series; and to establish the form and terms of debt securities of any series as permitted by the indenture.

The holders of a majority in principal amount of outstanding debt securities of any series may waive compliance with certain restrictive covenants and provisions of the applicable indenture.

Discharge

Unless otherwise indicated in an applicable prospectus supplement, each indenture provides that we may satisfy and discharge our obligations thereunder with respect to the debt securities of any series, when either:

all debt securities of that series that have been authenticated, except lost, stolen or destroyed debt securities of that series that have been replaced or paid and debt securities of that series for whose payment money has been deposited in trust and thereafter repaid to us, have been delivered to the trustee for cancellation; or

all debt securities of that series that have not been delivered to the trustee for cancellation have become due and payable by reason of the mailing of a notice of redemption or otherwise or will become due and payable within one year and we or, if applicable, any guarantor has irrevocably deposited or caused to be deposited with the trustee as trust funds in trust solely for the benefit of the holders of debt securities of that series, cash, non-callable U.S. government securities, or a combination thereof, in amounts as will be sufficient without consideration of any reinvestment of interest, to pay and discharge the entire indebtedness on the debt securities of that series not delivered to the trustee for cancellation for principal, premium, if any, and accrued interest to the date of maturity or redemption.

Defeasance

Unless otherwise indicated in an applicable prospectus supplement, each indenture provides that we may, at our option and at any time, elect to have all of our obligations discharged with respect to the outstanding debt securities of a series and, if applicable, all obligations of the guarantors discharged with respect to their guarantees (legal defeasance) except for:

the rights of holders of the outstanding debt securities of that series to receive payments in respect of the principal of, or premium or interest, if any, on the debt securities of that series when such payments are due from the trust referred to below;

our obligations with respect to the debt securities of that series concerning issuing temporary securities, registration of securities, mutilated, destroyed, lost or stolen securities and the maintenance of an office or agency for payment and money for security payments held in trust;

the rights, powers, trusts, duties and immunities of the applicable trustee, our obligations and, if applicable, the guarantor s obligations in connection therewith; and

the legal defeasance provisions of the indenture.

In addition, we may, at our option and at any time, elect to have our obligations and, if applicable, the guarantors obligations released with respect to certain covenants in respect of the debt securities of any series that are described in the indenture (covenant defeasance) and thereafter any omission to comply with those covenants will not constitute a default or event of default with respect to the debt securities of that series. In the event covenant defeasance occurs, certain events (not including non-payment, bankruptcy, receivership, rehabilitation and insolvency events) described under Events of Default and Remedies will no longer constitute an event of default with respect to the debt securities of that series.

In order to exercise either legal defeasance or covenant defeasance we are required to meet specified conditions, including:

- we must irrevocably deposit with the trustee, in trust, for the benefit of the holders of the debt securities of that series, cash, non-callable U.S. government securities, or a combination thereof, in amounts as will be sufficient to pay the principal of, or premium and interest, if any, on the outstanding debt securities of that series on the stated maturity or on the applicable redemption date, as the case may be;

in the case of legal defeasance, we have delivered to the applicable trustee an opinion of counsel reasonably acceptable to the trustee confirming that (a) we have received from, or there has been published by, the Internal Revenue Service a ruling or (b) since the date of the indenture, there has been a change in the applicable federal income tax law, in either case to the effect that, and based thereon such opinion of counsel will confirm that, the holders of the outstanding debt securities of that series will not recognize income, gain or loss for federal income tax purposes as a result of such legal defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such legal defeasance had not occurred; and

in the case of covenant defeasance, we have delivered to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that the holders of the outstanding debt securities of that series will not recognize income, gain or loss for federal income tax purposes as a result of such covenant defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such covenant defeasance had not occurred.

The Trustees under the Indentures

If a trustee becomes a creditor of ours or any guarantor, the indenture limits its right to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. Each trustee will be permitted to engage in other transactions with us and/or the guarantors, if any; however, if any trustee acquires any conflicting interest it must eliminate such conflict within 90 days, apply to the SEC for permission to continue or resign.

The holders of a majority in principal amount of the then outstanding debt securities of a series will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the trustee, subject to certain exceptions. The indenture provides that in case an event of default occurs and is continuing, a trustee will be required, in the exercise of its power, to use the degree of care of a prudent person in the conduct of its own affairs. Subject to such provisions, a trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any holder of debt securities, unless such holder has offered to the trustee security and indemnity satisfactory to it against any loss, liability or expense.

Applicable Law

The debt securities and the indentures will be governed by and construed in accordance with the laws of the State of Delaware.

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DESCRIPTION OF WARRANTS

We may issue, either separately or together with other securities, warrants for the purchase of any of the other types of securities that we may sell under this prospectus.

This section summarizes the general terms of the warrants that we may offer. The warrants will be issued under warrant agreements to be entered into between us and a bank or trust company, as warrant agent. The prospectus supplement relating to a particular series of warrants will describe the specific terms of that series, which may be in addition to or different from the general terms summarized in this section. The summaries in this section and the prospectus supplement do not describe every aspect of the warrants. If any particular terms of a series of warrants described in a prospectus supplement differ from any of the terms described in this prospectus, then the terms described in the applicable prospectus supplement will be deemed to supersede the terms described in this prospectus. When evaluating the warrants, you also should refer to all the provisions of the applicable warrant agreement, the certificates representing the warrants and the specific descriptions in the applicable prospectus supplement. The applicable warrant agreement and warrant certificates will be filed as exhibits to or incorporated by reference in the registration statement.

General

The prospectus supplement will describe the terms of the warrants in respect of which this prospectus is being delivered as well as the related warrant agreement and warrant certificates, including the following, where applicable:

- the principal amount of, or the number of securities, as the case may be, purchasable upon exercise of each warrant and the initial price at which the principal amount or number of securities, as the case may be, may be purchased upon such exercise;
- the designation and terms of the securities, if other than common units, purchasable upon exercise thereof and of any securities, if other than common units, with which the warrants are issued;
- the procedures and conditions relating to the exercise of the warrants;
- the date, if any, on and after which the warrants, and any securities with which the warrants are issued, will be separately transferable;
- the offering price of the warrants, if any;
- the date on which the right to exercise the warrants will commence and the date on which that right will expire;
- a discussion of any special United States federal income tax considerations applicable to the warrants;
- whether the warrants represented by the warrant certificates will be issued in registered or bearer form, and, if registered, where they may be transferred and registered;

call provisions of the warrants, if any;

antidilution provisions of the warrants, if any; and

any other material terms of the warrants.

Exercise of Warrants

Each warrant will entitle the holder to purchase for cash that principal amount of or number of securities, as the case may be, at the exercise price set forth in, or to be determined as set forth in, the applicable prospectus supplement relating to the warrants. Unless otherwise specified in the applicable prospectus supplement, warrants may be exercised at the corporate trust office of the warrant agent or any other office indicated in the applicable prospectus supplement at any time up to 5:00 p.m. Eastern Standard Time on the expiration date set

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forth in the applicable prospectus supplement. After 5:00 p.m. Eastern Standard Time on the expiration date, unexercised warrants will become void. Upon receipt of payment and the warrant certificate properly completed and duly executed, we will, as soon as practicable, issue the securities purchasable upon exercise of the warrant. If less than all of the warrants represented by the warrant certificate are exercised, a new warrant certificate will be issued for the remaining amount of warrants.

No Rights of Security Holder Prior to Exercise

Prior to the exercise of their warrants, holders of warrants will not have any of the rights of holders of the securities purchasable upon the exercise of the warrants and will not be entitled to:

- in the case of warrants to purchase debt securities, payments of principal of, premium, if any, or interest, if any, on the debt securities purchasable upon exercise; or

- in the case of warrants to purchase equity securities, the right to vote or to receive dividend payments or similar distributions on the securities purchasable upon exercise.

Exchange of Warrant Certificates

Warrant certificates will be exchangeable for new warrant certificates of different denominations at the corporate trust office of the warrant agent or any other office indicated in the applicable prospectus supplement.

OUR PARTNERSHIP AGREEMENT

The following is a summary of our current partnership agreement which relates to our common units. Pursuant to our partnership agreement and this prospectus we may issue additional limited partner interests having different rights and characteristics. These rights and characteristics will be set forth in a prospectus supplement with respect to the issuance of any of these securities.

Organization and Duration

We were formed in May 1999. We will dissolve on December 31, 2098, unless sooner dissolved under the terms of our partnership agreement.

Purpose

Our purpose under our partnership agreement is limited to serving as the limited partner of our operating partnership and engaging in any business activity that may be engaged in by our operating partnership or that is approved by our general partner. The operating partnership agreement provides that our operating partnership may, directly or indirectly, engage in:

- operations as conducted on February 2, 2000, including the ownership and operation of our gathering systems;

- any other activity approved by our general partner, but only to the extent that our general partner reasonably determines that, as of the date of the acquisition or commencement of the activity, the activity generates qualifying income as that term is defined in Section 7704 of the Internal Revenue Code; or

- any activity that enhances the operations described above.

The Units

Our common units represent limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement.

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Limited Voting Rights

Holders of our units have limited voting rights and generally are entitled to vote only with respect to the following matters:

- a sale or exchange of all or substantially all of our assets;
- our dissolution or reconstitution;
- our merger; and
- termination or material modification of the omnibus agreement or master natural gas gathering agreement.

Removal of our general partner requires a two-thirds vote of all outstanding common units, excluding those held by our general partner and its affiliates. Our partnership agreement permits our general partner generally to make amendments to it that do not materially adversely affect unitholders without the approval of any unitholders.

Cash Distribution Policy

Quarterly Distributions of Available Cash. Our operating partnership is required by the operating partnership agreement to distribute to us, within 45 days of the end of each fiscal quarter, all of its available cash for that quarter. We, in turn, distribute to our partners all of the available cash received from our operating partnership for that quarter.

Available cash generally means, for any of our fiscal 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. We generally make distributions of all available cash within 45 days after the end of each quarter to holders of record on the applicable record date.

Distributions of Available Cash from Operating Surplus. Cash distributions are characterized as distributions from either operating surplus or capital surplus. This distinction affects the amounts distributed to unitholders relative to our general partner.

Operating surplus means:

- our cash balance, excluding cash constituting capital surplus, less all of our operating expenses, debt service payments, maintenance costs, capital expenditures and reserves established for future operations.

Capital surplus means capital generated only by borrowings other than working capital borrowings, sales of debt and equity securities and sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets disposed of in the ordinary course of business.

We treat all available cash distributed from any source as distributed from operating surplus until the sum of all available cash distributed since we began operations equals our total operating surplus from the date we began operations until the end of the quarter that immediately preceded the distribution. This method of cash distribution avoids the difficulty of trying to determine whether available cash is distributed from operating surplus or capital surplus. We treat any excess available cash, irrespective of its source, as capital surplus, which would represent a return of capital, and we will distribute it accordingly. For a discussion of distributions of capital surplus, see Distributions of Capital Surplus below.

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We distribute available cash from operating surplus for any quarter in the following manner:

- first, 98% to the common units, pro rata, and 2% to our general partner, until we have distributed $.42 for each outstanding common unit; and
- after that, in the manner described in Incentive Distribution Rights below.

The 2% allocation of available cash from operating surplus to our general partner includes our general partner s percentage interest in distributions from us and our operating partnership on a combined basis.

Adjusted operating surplus for any period generally means operating surplus generated during that period, less:

- any net increase in working capital borrowings during that period and
- any net reduction in cash reserves for operating expenditures during that period not relating to an operating expenditure made during that period,

and plus:

- any net decrease in working capital borrowings during that period and
- any net increase in cash reserves for operating expenditures during that period required by any debt instrument for the repayment of principal, interest or premium.

Operating surplus generated during a period is equal to the difference between:

- the operating surplus determined at the end of that period and
- the operating surplus determined at the beginning of that period.

Incentive Distribution Rights. By incentive distribution rights we mean our general partner s right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after we have made the minimum quarterly distributions and we have met specified target distribution levels, as described below. Our general partner may transfer its incentive distribution rights separately from its general partner interest without the consent of the unitholders.

We make incentive distributions to our general partner for any quarter in which we have distributed available cash from operating surplus to the common unitholders in an amount equal to the minimum quarterly distribution. If this condition is satisfied, the remaining available cash will be distributed as follows:

- first, 85% to all units, pro rata, and 15% to our general partner, until each unitholder has received a total of $.52 per unit for that quarter, in addition to any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution on the common units;

- second, 75% to all units, pro rata, and 25% to our general partner, until each unitholder has received a total of $.60 per unit for that quarter, in addition to any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution on the common units; and

- after that, 50% to all units, pro rata, and 50% to our general partner.

The distributions to our general partner that exceed its aggregate 2% general partner interest represent the incentive distribution rights.

Distributions from Capital Surplus. We distribute available cash from capital surplus in the following manner:

- first, 98% to all units, pro rata, and 2% to our general partner, until each common unit has received distributions equal to $13.00 per unit; and

- after that, we will distribute all available cash from capital surplus, as if it were from operating surplus.

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When we make a distribution from capital surplus, we will treat it as if it were a repayment of your investment in your common units. For these purposes, the partnership agreement deems the investment to be $13.00 per common unit, which is the unit price from our initial public offering, regardless of the price you actually pay for your common units in this offering. To reflect this repayment, we will reduce the amount of the minimum quarterly distribution and the distribution levels at which our general partner s incentive distribution rights begin, which we refer to in this prospectus as target distribution levels, by multiplying each amount by a fraction, determined as follows:

the numerator is $13.00 less all distributions from capital surplus including the distribution just made, and

the denominator is $13.00 less all distributions from capital surplus excluding the distribution just made.

We refer to the initial public offering price of $13.00 per common unit, less any distributions from capital surplus, as the unrecovered unit price.

After the minimum quarterly distribution and the target distribution levels have been reduced to zero, we will treat all distributions of available cash from all sources as if they were from operating surplus. Because the minimum quarterly distribution and the target distribution levels will have been reduced to zero, our general partner will then be entitled to receive 50% of all distributions of available cash in its capacity as general partner and holder of the incentive distribution rights, in addition to any distributions to which it may be entitled as a holder of units.

Distributions from capital surplus will not reduce the minimum quarterly distribution or target distribution levels for the quarter in which they are distributed.

Adjustment of Minimum Quarterly Distribution and Target Distribution Levels. In addition to adjustments made upon a distribution of available cash from capital surplus, we will proportionately adjust each of the following upward or downward, as appropriate, if any combination or subdivision of units occurs:

the minimum quarterly distribution,

the target distribution levels,

the unrecovered unit price,

the number of common units issuable upon conversion of the subordinated units, and

other amounts calculated on a per unit basis.

For example, if a two-for-one split of the common units occurs, we will reduce the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price of the common units to 50% of their initial levels.

We will not make any adjustment for the issuance of additional common units for cash or property.

We may also adjust the minimum quarterly distribution and the target distribution levels if legislation is enacted or if existing law is modified or interpreted in a manner that causes us or our operating partnership to become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes. In this event, we will reduce the minimum quarterly distribution and the target distribution levels for each quarter after that time to amounts equal to the product of:

- the minimum quarterly distribution and each of the target distribution levels multiplied by
- one minus the sum of:
  - the highest marginal federal income tax rate which could apply to the partnership that is taxed as a corporation plus

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any increase in the effective overall state and local income tax rate that would have been applicable in the preceding calendar year as a result of the new imposition of the entity level tax, after taking into account the benefit of any deduction allowable for federal income tax purposes for the payment of state and local income taxes, but only to the extent of the increase in rates resulting from that legislation or interpretation.

For example, assuming we are not previously subject to state and local income tax, if we became taxable as a corporation for federal income tax purposes and subject to a maximum marginal federal, and effective state and local, income tax rate of 40%, then we would reduce the minimum quarterly distribution and the target distribution levels to 60% of the amount immediately before the adjustment.

Distributions of Cash Upon Liquidation. When we commence dissolution and liquidation, we will sell or otherwise dispose of our assets and adjust the partners capital account balances to reflect any resulting gain or loss. We will first apply the proceeds of liquidation to the payment of our creditors in the order of priority provided in our partnership agreement and by law. After that, we will distribute the proceeds to the unitholders and our general partner in accordance with their capital account balances, as so adjusted.

We maintain capital accounts in order to ensure that the partnership s allocations of income, gain, loss and deduction are respected under the Internal Revenue Code. The balance of a partner s capital account also determines how much cash or other property the partner will receive on liquidation of the partnership. A partner s capital account is credited with (increased by) the following items:

the amount of cash and fair market value of any property (net of liabilities) contributed by the partner to the partnership, and

the partner s share of book income and gain (including income and gain exempt from tax).

A partner s capital account is debited with (reduced by) the following items:

the amount of cash and fair market value (net of liabilities) of property distributed to the partner, and

the partner s share of loss and deduction (including some items not deductible for tax purposes).

Partners are entitled to liquidating distributions in accordance with their capital account balances.

Upon our liquidation, any gain, or unrealized gain attributable to assets distributed in kind, will be allocated to the partners in the following manner:

first, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

second, 98% to the common units, pro rata, and 2% to our general partner, until the capital account for each common unit is equal to the sum of:

the unrecovered unit price, and

the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs.

third, 85% to all units, pro rata, and 15% to our general partner, until there has been allocated under this paragraph an amount per unit equal to:

the excess of the $.52 target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence less

the cumulative amount per unit of any distribution of available cash from operating surplus in excess of the minimum quarterly distribution per unit that was distributed 85% to the units, pro rata, and 15% to our general partner for each quarter of our existence;

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fourth, 75% to all units, pro rata, and 25% to our general partner, until there has been allocated under this paragraph an amount per unit equal to:

the excess of the $.60 target distribution per unit over the $.52 target distribution per unit for each quarter of our existence less

the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that was distributed 75% to the units, pro rata, and 25% to our general partner for each quarter of our existence; and

after that, 50% to all units, pro rata, and 50% to our general partner.

Upon our liquidation, any loss will generally be allocated to our general partner and the unitholders in the following manner:

first, 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to our general partner, until the capital accounts of the common unitholders have been reduced to zero; and

after that, 100% to our general partner.

In addition, we will make interim adjustments to the capital accounts at the time we issue additional equity interests or make distributions of property. We will base these adjustments on the fair market value of the interests or the property distributed and we will allocate any gain or loss resulting from the adjustments to the unitholders and our general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive interim adjustments to the capital accounts, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional equity interests, our distributions of property, or upon our liquidation, in a manner which results, to the extent possible, in the capital account balances of our general partner equaling the amount which would have been our general partner s capital account balances if we had not made any earlier positive adjustments to the capital accounts.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder and executes and delivers a transfer application, grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution and the amendment of our partnership agreement, and to make consents and waivers under our partnership agreement.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under Limited Liability.

Limited Liability

So long as a limited partner does not participate in the control of our business within the meaning of the Delaware Revised Uniform Limited Partnership Act and otherwise acts in conformity with the provisions of our partnership agreement, the limited partner s liability under the Delaware Act will be limited to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined that a limited partner participated in the control of our business, then the limited partner could be held personally liable for our obligations under Delaware law to the same extent as our general partner. This liability would extend only to persons who transact business with us who reasonably believe that the limited partner is a general partner. However, what constitutes participating in the control of a limited partnership s business has not been clearly established in all states. If it were determined, for example, that the right, or exercise of a right, by the limited partners to:

- remove our general partner,

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- approve some amendments to our partnership agreement, or
- take other action under our partnership agreement

constituted participation in the control of our business, then limited partners could be held liable for our obligations to the same extent as our general partner.

Under the Delaware Act, we cannot make a distribution to a partner if, after the distribution, all our liabilities, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property, exceed the fair value of our assets. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act is liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, an assignee who becomes a substituted limited partner is liable for the obligations of his assignor to make contributions to the partnership, except the assignee is not obligated for liabilities unknown to him at the time he became a limited partner and which he could not ascertain from our partnership agreement.

Our operating partnership currently conducts business in New York, Ohio, Oklahoma, Pennsylvania and Texas. The limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established in many jurisdictions. If it were determined that we were, by virtue of our limited partner interest in our operating partnership or otherwise, conducting business in any state under the applicable limited partnership statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the control of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner. We operate in a manner our general partner considers reasonable and appropriate to preserve the limited liability of the limited partners.

Transfer Agent and Registrar

American Stock Transfer and Trust Company is our registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except that the following fees must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges,
- special charges for services requested by a holder of a common unit, and
- other similar fees or charges.

There is no charge to unitholders for disbursements of cash distributions.

We will indemnify the transfer agent, its agents and each of their particular shareholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted in its capacity as our transfer agent, except for any liability due to any negligence, gross negligence, bad faith or intentional misconduct of the indemnified person or entity.

Transfer of Common Units

The transfer agent will not record a transfer of common units, and we will not recognize the transfer, unless the transferee executes and delivers a transfer application. The form of transfer application appears on the reverse side of the certificates representing the common units. By executing and delivering a transfer application, the transferee of common units:

- becomes the record holder of the common units and is an assignee until admitted as a substituted limited partner;

automatically requests admission as a substituted limited partner;

agrees to be bound by the terms and conditions of our partnership agreement;

represents that the transferee has the capacity, power and authority to enter into our partnership agreement;

grants powers of attorney to officers of our general partner and our liquidator, as specified in our partnership agreement; and

makes the consents and waivers contained in our partnership agreement.

An assignee will become a substituted limited partner as to the transferred common units upon the consent of our general partner and the recordation of the name of the assignee on our books and records. Our general partner may withhold its consent in its sole discretion.

A transferee s broker, agent or nominee may complete, execute and deliver the transfer applications. We are entitled to treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfer of securities. In addition to the rights acquired upon transfer, the transferor gives the transferee the right to request admission as a substituted limited partner. A purchaser or transferee of common units who does not execute and deliver a transfer application will have only

the right to assign the common units to a purchaser or other transferee and

the right to transfer the right to seek admission as a substituted limited partner.

Thus, a purchaser or transferee of common units who does not execute and deliver a transfer application will not receive

cash distributions or federal income tax allocations unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application and

may not receive federal income tax information or reports furnished to record holders of common units.

The transferor of common units must provide the transferee with all information necessary to transfer the common units. The transferor will not be required to insure the execution of the transfer application by the transferee and will have no liability or responsibility if the transferee neglects or chooses not to execute and forward the transfer application to the transfer agent. See Status as Limited Partner or Assignee.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations, even if either of us has notice of an attempted transfer.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional limited partner interests, debt and other securities for the consideration and on the terms and conditions established by our general partner in its sole discretion without the approval of any limited partners. We have funded, and will likely continue to fund, acquisitions through the issuance of additional common units or other equity securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

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In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, in the sole discretion of our general partner, may have special voting rights to which the common units are not entitled.

Upon issuance of additional partnership securities, our general partner must make additional capital contributions to the extent necessary to maintain its combined 2% general partner interest in us and in our operating partnership. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other equity securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain its percentage interest that existed immediately before each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of Our Partnership Agreement

Amendments to our partnership agreement may be proposed only by or with the consent of our general partner, which it may withhold in its sole discretion. In order to adopt a proposed amendment, other than the amendments discussed in No Unitholder Approval below, our general partner must seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment.

Prohibited Amendments. No amendment may be made that would:

- change the percentage of outstanding units required to take partnership action, unless approved by the affirmative vote of unitholders constituting at least the voting requirement sought to be reduced;
- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected;
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without its consent, which may be given or withheld in its sole discretion;
- change our term;
- provide that we are not dissolved upon the expiration of our term or upon an election to dissolve us by our general partner that is approved by holders of a majority of the units of each class; or
- give any person the right to dissolve us other than our general partner s right to dissolve us with the approval of holders of a majority of the units of each class.

The provision of our partnership agreement preventing the amendments having the effects described above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class.

No Unitholder Approval. Our general partner may amend our partnership agreement, without the approval of the unitholders, to:

- change our name, the location of our principal place of business, our registered agent or registered office;

- reflect the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

- qualify us or continue our qualification as a limited partnership under the laws of any state or to ensure that neither we nor our operating partnership will be taxed as a corporation or otherwise taxed as an entity for federal income tax purposes;

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- prevent us or our general partner, or its directors, officers, agents or trustees, from being subject to the provisions of the Investment Advisers Act of 1940 or plan asset regulations adopted under the Employee Retirement Income Security Act of 1974;
- authorize additional limited or general partner interests;
- reflect changes required by a merger agreement that has been approved under the terms of our partnership agreement;
- permit us to form or invest in any entity, other than the operating partnership, permitted by our partnership agreement;
- change our fiscal year or taxable year; and
- make other changes substantially similar to any of the matters described above.

In addition, our general partner may amend our partnership agreement, without the approval of the unitholders, if those amendments:

- do not adversely affect the limited partners in any material respect;
- are necessary to satisfy any requirements or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary to facilitate the trading of limited partner interests or to comply with any rule or guideline of any securities exchange or interdealer quotation system on which the limited partner interests are or will be listed for trading;
- are necessary for any action taken by our general partner relating to splits or combinations of units; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval. Except in the case of the amendments described above under No Unitholder Approval, amendments to our partnership agreement will not become effective without the approval of holders of at least 90% of the units unless we obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any limited partner or cause us or our operating partnership to be taxable as a corporation or otherwise to be taxed as an entity for federal income tax purposes (to the extent not previously taxed as such). Subject to obtaining the opinion of counsel, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected.

Merger, Sale or Other Disposition of Our Assets

Our general partner may not, without the prior approval of holders of a majority of the outstanding units, cause us to sell, exchange or otherwise dispose of all of substantially all of our assets, including by way of merger, consolidation or other combination, or approve on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our operating partnership. However, our general partner may mortgage or otherwise grant a security interest in all or substantially all of our assets or sell all or substantially all of our assets under a foreclosure without that approval. Furthermore, provided that conditions specified in our partnership agreement are satisfied, our general partner may merge us or any of our subsidiaries into, or convey some or all of our and their assets to, a newly formed entity if the sole purpose of that merger or conveyance changes our legal form into another limited liability entity.

The unitholders are not entitled to dissenters rights of appraisal in the event of a merger, consolidation, sale of substantially all of our assets or any other transaction or event.

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Termination and Dissolution

We will continue until December 31, 2098, unless terminated sooner upon:

- the election of our general partner to dissolve us, if approved by the holders of a majority of the outstanding units;
- the sale, exchange or other disposition of all or substantially all of our assets and those of our operating partnership;
- the entry of a decree of judicial dissolution of us; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than the transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last item above, the holders of a majority of the units may also elect, within specific time limitations, to reconstitute us by forming a new limited partnership on terms identical to those in our partnership agreement and having as general partner an entity approved by the holders of a majority of the units subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner and
- we, the reconstituted limited partnership, and the operating partnership would not be taxed as a corporation or otherwise be taxed as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Unless we are reconstituted and continue as a new limited partnership, upon our liquidation the liquidator will liquidate our assets and apply the proceeds of the liquidation as described in Cash Distribution Policy Distributions of Cash Upon Liquidation. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to the partners.

Withdrawal or Removal of Our General Partner

Our general partner may withdraw as our general partner without first obtaining approval from the unitholders by giving 90 days written notice. Our general partner may also sell or otherwise transfer all of its general partner interests in us without the approval of the unitholders as described below under Transfer of General Partner Interest and Incentive Distribution Rights. Upon withdrawal, we must reimburse our general partner for all expenses incurred by it on our behalf or allocable to us in connection with operating our business.

If our general partner withdraws, other than as a result of a transfer of all or a part of its general partner interests in us, the holders of a majority of the units may elect a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved and liquidated, unless within 180 days after that withdrawal the holders of a majority of the units agree in writing to continue our business and to appoint a successor general partner. See Termination and Dissolution.

Our general partner may not be removed except by the vote of the holders of at least 66 $^{2}/3$% of the outstanding common units, excluding common units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal is also subject to the approval of a successor general partner by the vote of the holders of a majority of the common units, excluding common units held by our general partner and its affiliates. If our general partner is removed under circumstances where cause does not exist and does not consent to that removal:

- the agreement of Atlas America to connect wells to our gathering systems will terminate;

the master natural gas gathering agreement with Atlas America will not apply to any future wells drilled by Atlas America although it will continue as to wells connected to the gathering system at the time of removal;

the obligations of Atlas America to provide assistance for the extension of our gathering systems and in the identification and acquisition of gathering systems from third parties will terminate; and

our general partner will have the right to convert its general partner interests and incentive distribution rights into common units or to receive cash in exchange for those interests from the successor general partner.

Our partnership agreement defines cause as existing where a court has rendered a final, non-appealable judgment that our general partner has committed fraud, gross negligence or willful or wanton misconduct in its capacity as general partner.

Withdrawal or removal of our general partner as our general partner also constitutes its withdrawal or removal as the general partner of our operating partnership.

In the event of removal of our general partner under circumstances where cause exists or a withdrawal of our general partner that violates our partnership agreement, a successor general partner will have the option to purchase the general partner interests and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed, the departing general partner will have the option to require the successor general partner to purchase those interests for their fair market value. In each case, fair market value will be determined by agreement between the departing general partner and the successor general partner. If they cannot reach an agreement, an independent expert selected by the departing general partner and the successor general partner will determine the fair market value. If the departing general partner and the successor general partner cannot agree on an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value. If the purchase option is not exercised by either the departing general partner or the successor general partner, the general partner interests and incentive distribution rights will automatically convert into common units equal to the fair market value of those interests. The successor general partner must indemnify the departing general partner (or its transferee) from all of our debt and liability arising on or after the date on which the departing general partner becomes a common unitholder as a result of the conversion. Except for this limited indemnity right and the right of the departing general partner to receive distributions on its common units, no other payments will be made to our general partner after withdrawal.

Transfer of General Partner Interest and Incentive Distribution Rights

Our general partner may transfer all or any part of its general partner interest without obtaining the consent of the unitholders. As a condition to the transfer of a general partner interest, the transferee must assume the rights and duties of the general partner to whose interest it has succeeded, furnish an opinion of counsel regarding limited liability and tax matters, agree to acquire all of the general partner s interest in our operating partnership and agree to be bound by the provisions of the partnership agreement of our operating partnership.

The members of our general partner may sell or transfer all or part of their interest in our general partner to an affiliate without the approval of the unitholders. Atlas America and its affiliates have agreed that they will not divest their interest in our general partner without also divesting to the same acquiror their ownership interest in subsidiaries which act as the general partner of oil and gas investment partnerships sponsored by them.

Our general partner or a later holder may transfer its incentive distribution rights to an affiliate or another person as part of its merger or consolidation with or into, or sale of all or substantially all of its assets to, that person without the prior approval of the unitholders. However, the transferee must agree to be bound by the provisions of our partnership agreement.

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Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Atlas Pipeline Partners GP, LLC as our general partner or otherwise change management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group will lose voting rights on all of its units and the units will not be considered outstanding for the purposes of noticing meetings, determining the presence of a quorum, calculating required votes and other similar matters. In addition, the removal of our general partner under circumstances where cause does not exist and our general partner does not consent to that removal has the adverse consequences described under Withdrawal or Removal of Our General Partner.

Limited Call Right

If at any time not more than 20% of the outstanding limited partner interests of any class are held by persons other than our general partner and its affiliates, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining limited partner interests of the class held by unaffiliated persons as of a record date selected by our general partner on at least 10 but not more than 60 days notice. The purchase price is the greater of:

- the highest cash price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests and

- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner s right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Meetings; Voting

Except as described above under Change of Management Provisions, unitholders or assignees who are record holders of units on a record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited. Common units that are owned by an assignee who is a record holder, but who has not yet been admitted as a substituted limited partner, will be voted by our general partner at the written direction of the record holder. Absent direction of this kind, the common units will not be voted, except that, in the case of common units held by our general partner on behalf of non-citizen assignees, our general partner shall distribute the votes on those common units in the same ratios as the votes of limited partners on other units are cast.

Any action to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the same number of units as would be necessary to take the action. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Except as described above under Change of Management Provisions, each record holder will have a vote in accordance with his percentage interest, although additional limited partner interests having different voting rights could be issued. See Issuance of Additional Securities. Units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner.

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We or the transfer agent will deliver any notice, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement to the record holder.

Status as Limited Partner or Assignee

An assignee of a common unit, after executing and delivering a transfer application, but pending its admission as a substituted limited partner, is entitled to an interest equivalent to that of a limited partner sharing in allocations and distributions, including liquidating distributions. Our general partner will vote and exercise other powers attributable to common units owned by an assignee who has not become a substituted limited partner at the written direction of the assignee. See Meetings; Voting. We will not treat transferees who do not execute and deliver a transfer application as assignees or as record holders of common units, and they will not receive cash distributions, federal income tax allocations or reports furnished to record holders. See Transfer of Common Units.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property in which we have an interest because of the nationality, citizenship or related status of any limited partner or assignee, we may redeem the units held by the limited partner or assignee at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner or assignee to furnish information about his nationality, citizenship or related status. If a limited partner or assignee fails to furnish this information within 30 days after a request for it, or our general partner determines after receipt of the information that the limited partner or assignee is not an eligible citizen, then the limited partner or assignee may be treated as a non-citizen assignee. In addition to other limitations on the rights of an assignee who is not a substituted limited partner, a non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Indemnification

Under the partnership agreement, we will indemnify the following persons, by reason of their status as such, to the fullest extent permitted by law, from and against all losses, claims or damages arising out of or incurred in connection with our business:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a member, partner, officer, director, employee, agent or trustee of our general partner, any departing general partner or the operating partnership or any affiliate of a general partner, any departing general partner or the operating partnership; or

any person who is or was serving at the request of a general partner or any departing general partner or any affiliate of a general partner or any departing general partner as an officer, director, employee, member, partner, agent, fiduciary or trustee of another person.

Our indemnification obligation arises only if the indemnified person acted in good faith and in a manner the person reasonably believed to be in, and not opposed to, our best interests. With respect to criminal proceedings, the indemnified person must not have had reasonable cause to believe that the conduct was unlawful.

Any indemnification under these provisions will be only out of our assets. Our general partner will not be personally liable for the indemnification obligations and will not have any obligation to contribute or loan funds to us in connection with it. The partnership agreement permits us to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under the partnership agreement.

Books and Reports

Our general partner keeps appropriate books on our business at our principal offices. The books are maintained for both tax and financial reporting purposes on an accrual basis. For tax and financial reporting purposes, our fiscal year is the calendar year.

We furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we also furnish or make available summary financial information within 90 days after the close of each quarter.

We furnish each record holder information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. We expect to furnish information in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders depends on the cooperation of unitholders in supplying us with specific information. We will furnish every unitholder with information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of our partnership agreement, the certificate of limited partnership and related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and

other information regarding our affairs that is just and reasonable.

Our general partner intends to keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or which we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under the partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates if an exemption from the registration requirements is not otherwise available. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions.

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EXPERTS

The consolidated financial statements of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004; the financial statements of ETC Oklahoma Pipeline, Ltd. as of August 31, 2004 and 2003 and for the year ended August 31, 2004 and for the eleven month period ended August 31, 2003; and the financial statements of the Elk City System (a division of Aquila Gas Pipeline Corporation) for the year ended September 30, 2002 have been audited by Grant Thornton LLP, independent registered public accountants, as indicated in their reports with respect thereto, and are incorporated by reference herein in reliance upon the authority of such firm as experts in giving such reports.

LEGAL MATTERS

The validity of the securities offered hereby and tax matters will be passed upon for us by Ledgewood, Philadelphia, Pennsylvania.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-3 with respect to this offering. This prospectus only constitutes part of the registration statement and does not contain all of the information set forth in the registration statement, its exhibits and its schedules.

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC s web site at *http://www.sec.gov*. You may also read and copy any document we file at the SEC s public reference rooms. Please call the SEC at 1-800-SEC-0330 for additional information on the public reference rooms.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The SEC allows us to incorporate by reference the information we file with it. This means that we can disclose important information to you by referring to these documents. The information incorporated by reference is an important part of this prospectus, and information that we file later with the SEC under Sections 13(a) or 15(d) of the Securities Exchange Act of 1934 will automatically update and supersede this information.

We are incorporating by reference the following documents that we have previously filed with the SEC (other than information in such documents that is deemed not to be filed):

- our Annual Report on Form 10-K for the fiscal year ended December 31, 2004;
- our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2005 and June 30, 2005; and

our Current Reports on Form 8-K filed March 14, 2005, March 22, 2005, April 18, 2005, May 11, 2005, May 24, 2005 and May 27, 2005.

You may obtain a copy of these filings without charge by writing or calling us at:

Investor Relations

Atlas Pipeline Partners, L.P.

311 Rouser Road

P.O. Box 611

Moon Township, Pennsylvania 15108

(412) 262-2830

You should rely only on the information incorporated by reference or provided in this prospectus. We have not authorized anyone else to provide you with different information. We are not making an offer to sell these securities or soliciting an offer to buy these securities in any state where the offer or sale is not permitted. You should not assume that the information in this prospectus or the documents we have incorporated by reference is accurate as of any date other than the date on the front of those documents.

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PLAN OF DISTRIBUTION

We may distribute the securities from time to time in one or more transactions at a fixed price or prices. We may change these prices from time to time. We may also distribute our securities at market prices prevailing at the time of sale, at prices related to prevailing market prices or at negotiated prices. We will describe the distribution method for each offering in a prospectus supplement.

We may sell our securities in any of the following ways:

- through underwriters or dealers,
- through agents who may be deemed to be underwriters as defined in the Securities Act, or
- directly to one or more purchasers.

The prospectus supplement for a particular offering will set forth the terms of the offering, purchase price, the proceeds we will receive from the offering, any delayed delivery arrangements, and any underwriting arrangements, including underwriting discounts and other items constituting underwriters compensation and any discounts or concessions allowed or reallowed or paid to dealers. We may have agreements with the underwriters, dealers and agents who participate in the distribution to indemnify them against certain civil liabilities, including liabilities under the Securities Act, or to contribute to payments which they may be required to make.

Securities offered may be a new issue of securities with no established trading market. Any underwriters to whom or agents through whom these securities are sold by us for public offering and sale may make a market in these securities, but such underwriters or agents will not be obligated to do so and may discontinue any market making at any time without notice. No assurance can be given as to the liquidity of or the trading market for any such securities.

If we use underwriters in the sale, the securities we offer will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions, including negotiated transactions, at a fixed public offering price or at varying prices determined at the time of sale. Our securities may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more firms acting as underwriters. The underwriter or underwriters with respect to a particular underwritten offering of securities will be named in the prospectus supplement relating to that offering, and if an underwriting syndicate is used, the managing underwriter or underwriters will be set forth on the cover of that prospectus supplement.

Securities offered may be a new issue of securities with no established trading market. Any underwriters to whom or agents through whom these securities are sold by us for public offering and sale may make a market in these securities, but such underwriters or agents will not be obligated to do so and may discontinue any market making at any time without notice. No assurance can be given as to the liquidity of or the trading market for any such securities.

If we use dealers in an offering, we will sell the securities to the dealers as principals. The dealers may then resell the securities to the public at varying prices to be determined by those dealers at the time of resale. The names of the dealers and the terms of the transaction will be set forth in a prospectus supplement. Any initial public offering price and any discounts or concessions allowed or reallowed or paid to dealers may be changed from time to time.

We may also offer our securities directly, or though agents we designate, from time to time at fixed prices, which we may change, or at varying prices determined at the time of sale. We will name any agent we use and describe the terms of the agency, including any commissions payable by us to the agent, in a prospectus supplement. Unless otherwise indicated in the prospectus supplement, any agent we use will act on a reasonable best efforts basis for the period of its appointment.

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2,700,000 Common Units

Representing Limited Partner Interests

PROSPECTUS SUPPLEMENT

November 21, 2005

LEHMAN BROTHERS

Sole Book-Running Manager

CITIGROUP

A.G. EDWARDS

FRIEDMAN BILLINGS RAMSEY

WACHOVIA SECURITIES

KEYBANC CAPITAL MARKETS

SANDERS MORRIS HARRIS